STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

January 23, 2024 - 10:02 a.m. **Day 2**
21 South Fruit Street
Suite 10
Concord, NH

RE: **DE 23-039**
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. d/b/a LIBERTY UTILITIES:
Request for Change in Distribution Rates.
(Hearing regarding Motion to Dismiss)

PRESENT: Chairman Daniel C. Goldner, *Presiding*
Commissioner Pradip K. Chattopadhyay
Commissioner Carleton B. Simpson

Alexander Speidel, Esq./*PUC Legal Advisor*

Doreen Borden, Clerk

APPEARANCES: **Reptg. Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities:**
Jessica A. Ralston, Esq. *(Keegan Werlin)*
Michael J. Sheehan, Esq.

Reptg. Trustees of Dartmouth College:
Thomas B. Getz, Esq. *(McLane Middleton)*

Court Reporter: Steven E. Patnaude, LCR No. 52

APPEARANCES: ***(C o n t i n u e d)***

Reptg. Residential Ratepayers:
Donald M. Kreis, Esq., Consumer Adv.
Michael Crouse, Esq.
Office of Consumer Advocate

Reptg. New Hampshire Dept. of Energy:
Paul B. Dexter, Esq.
Matthew C. Young, Esq.
Alexandra K. Ladwig, Esq.
(Regulatory Support Division)

INDEX

E X H I B I T S

EXHIBIT NO.	D E S C R I P T I O N	PAGE NO.
6	Liberty Utilities Updated Revenue Requirement Schedule	*premarked*
7	Liberty SAP Conversion Overview	*premarked*
8	New Hampshire Department of Energy Motion to Dismiss, including Attachments 1-15	*premarked*
9	**RESERVED** *(For a "clean" copy of the FERC Form 1 referenced and filed in this docket)*	110

P R O C E E D I N G

CHAIRMAN GOLDNER: Okay. Good morning. I'm Chairman Goldner. I'm here with Commissioner Simpson and Commissioner Chattopadhyay.

This is the continued hearing for the Department of Energy's Motion to Dismiss the Company's Rate Case Petition, as scheduled by the Commission's procedural order issued on January 8th, 2024.

We take note of the Joint Exhibit and Witness List filed by the Company on January 16th. It proposes two four-person witness panels, one for the Company and one for the Department of Energy. It is our presumption that, despite the DOE witnesses being listed second, the DOE panel would, in fact, go first, as the DOE is the moving party for this Motion to Dismiss.

If there's any objection to this approach, or to the Hearing Exhibits 6, 7, and 8, we ask that these objections be raised when the parties make their appearances.

We'll now proceed with appearances, beginning with the Department of Energy, the moving party.

MR. DEXTER: Good morning, Mr. Chairman, Commissioners. Paul Dexter, appearing on behalf of the Department of Energy. I'm joined today by Co-Counsel Matthew Young and Alexandra Ladwig.

We have no objection to our witnesses taking the stand first, and we have no objection to the exhibits that were proposed by Liberty.

CHAIRMAN GOLDNER: Thank you, Attorney Dexter.

The Office of the Consumer Advocate?

MR. KREIS: Good morning, Mr. Chairman, Commissioners. I'm Donald Kreis, the Consumer Advocate. With me today is our Staff Attorney, Michael Crouse.

CHAIRMAN GOLDNER: Very good.

The Trustees of Dartmouth College?

MR. GETZ: Good morning, Mr. Chairman and Commissioners. I'm Tom Getz, from the law firm McLane Middleton, on behalf of Dartmouth College.

And Dartmouth College takes no position on the procedural approach this morning.

CHAIRMAN GOLDNER: Would the -- would the College like to reserve the right to question witnesses? Or, will you be a bystander today?

MR. GETZ: I expect to be a bystander. But, if something pops up, I may weigh in.

CHAIRMAN GOLDNER: Very good. Very good. Are there any other parties, outside the Company, here today?

[No indication given.]

CHAIRMAN GOLDNER: Okay. Seeing none. We'll move to Liberty?

MS. RALSTON: Good morning. On behalf of the Company, Jessica Ralston, from the law firm Keegan Werlin, and joined by Michael Sheehan, in-house counsel for the Company.

The Company has no objection to the exhibit identified by the Department of Energy.

I did want to note one issue regarding witnesses. Lauren Preston is on the Witness List for the Company. Ms. Preston is experiencing a family emergency this morning. We currently don't know for sure if she'll be able to join us.

As you noted, the Department will go first. So, I expect we can provide you an update before we get to the Company's panel. But I just wanted to mention that now.

CHAIRMAN GOLDNER: And, if Ms. Preston is not able to join, does the Company have a substitute witness?

MS. RALSTON: We don't have a substitute witness. Ms. Preston's area of expertise is, you know, largely related to customer issues, and I don't know how central they will be to today's discussion. So, we could take a record request, if necessary. But our hope is that she will be able to join us at some point today, it just may not be until this afternoon.

CHAIRMAN GOLDNER: Okay. Very good.

Okay. Are there any other preliminary matters, before we start with the DOE witness panel?

MR. DEXTER: None from the Department.

CHAIRMAN GOLDNER: Okay. Seeing none. We'll invite the DOE witness panel to take the stand, and for Mr. Patnaude to swear in the witnesses.

*(Whereupon **ELIZABETH E. NIXON,***

JACQUELINE M. TROTTIER, JAY E. DUDLEY, *and* ***KAREN J. MORAN*** *were duly sworn by the Court Reporter.)*

CHAIRMAN GOLDNER: And we can begin with direct, and Attorney Dexter and the Department of Energy.

MR. DEXTER: Thank you, Mr. Chairman.

I have a couple of introductory questions I'd like to ask the panel of witnesses. I'll ask the questions, and I'll ask each of you to answer in the order that you're seated, starting with Ms. Nixon.

ELIZABETH E. NIXON, SWORN

JACQUELINE M. TROTTIER, SWORN

JAY E. DUDLEY, SWORN

KAREN J. MORAN, SWORN

DIRECT EXAMINATION

BY MR. DEXTER:

Q Could you please identify yourself by stating your name and position with the Department of Energy please?

A (Nixon) My name is Elizabeth Nixon. And I'm the Electric Director.

A (Trottier) My name is Jacqueline Trottier. And

I'm a Utility Analyst in the Electric Division.
A (Dudley) Jay Dudley, Utilities Analyst for the Electric Division, Department of Energy.
A (Moran) Karen Moran, Director of the Audit Division, Department of Energy.
Q So, the Department of Energy filed testimony in this case on December 13th, 2023. Did each of you include testimony in that filing on December 13th?
A (Nixon) I did.
A (Trottier) I did.
A (Dudley) Yes, I did.
A (Moran) No, I did not.
Q And did that testimony contain a description of your educational and professional experience?
A (Nixon) Yes.
A (Trottier) Yes.
A (Dudley) Yes, it did.
Q And, Ms. Moran, you answered "no" to that question. So, I'd like at this time for you to provide a brief description of your educational and work experience, as it's relevant to this rate case and the Motion to Dismiss that's been filed by the Department?

A (Moran) I have a Bachelor of Arts from Stonehill College; a Master's degree in Business Administration from Franklin Pierce University; I have a graduate-level Certificate in Human Resource Management from Plymouth State University.

I started my audit career in 1987. I joined the PUC Audit Staff in 1999. I was promoted to Chief Auditor in 2012. I am a Certified Bank Auditor, Certified Financial Services Auditor. And I've attended the NARUC Staff Subcommittee on Economy and Finance seminars since I began here in 1980 -- or '90 -- sorry, 1999. And I'm also on the Board of the Staff Subcommittee.

Q And, if you started with the former Commission, now the DOE, in 1999, I'm calculating about 25 years at the agency. Has your work at the agency been virtually exclusively dedicated to performing audits of the utilities regulated by the agency?

A (Moran) Yes.

Q Thank you. So, I'd like to ask some more specific questions relevant to this case, and, in particular, relevant to the Motion to Dismiss that was filed in this case.

First of all, let me ask the panel, have each of you reviewed the Motion to Dismiss the rate case that we filed on December 13th?

A (Nixon) Yes.

A (Trottier) Yes.

A (Dudley) Yes, I have.

A (Moran) Yes.

Q Thank you. And turning specifically to Ms. Moran, I'd like to draw your attention to what's been marked in this case as "Exhibit 8". And Exhibit 8 in this case are the fifteen attachments that were included with the Motion to Dismiss filed December 13th. And they have all been bound together as "Exhibit 8". And Exhibit 8, Bates 001, is entitled "Audit Report".

Ms. Moran, was this Audit Report prepared by you or under your supervision?

A (Moran) Yes.

Q And it was issued October 25th, 2023, is that correct?

A (Moran) That's correct.

Q Is the information contained in the Audit Report

accurate to the best of your knowledge and belief?
A (Moran) Yes.
Q And do you stand by the facts and the findings in that report as accurate?
A (Moran) Yes.
Q Ms. Moran, over what time was the audit performed?
A (Moran) Our audit began in May of this year -- or, 2023. With a draft issued to the Company on October 12th -- or, sorry, on October 9th. We met with the Company on October 12th. Issued a revised draft, to which they responded. And we issued the Final Report on October 25th.
Q And have you, or the Audit Division that reports to you, performed any subsequent audit work on this Liberty rate case, in terms of updating the Audit Report or the findings?
A (Moran) No.
Q Okay. I'd like to turn specifically to the Motion to Dismiss that we filed in this case, also on December 13th. And I'd like to draw your attention in particular to Paragraphs 15 through 28, and also Paragraph 30. So, that basically

starts on Page 6 of the Motion, and takes us through till about Page 13.

Would you agree that those paragraphs in the Motion to Dismiss draw heavily from the findings that were laid out in the Audit Report?

A (Moran) Yes.

Q And do you agree with the statements that were made in those paragraphs in the Motion to Dismiss concerning the Audit Report?

A (Moran) Yes.

Q Do they accurate -- does the Motion accurately capture this basic findings of the Audit Report?

A (Moran) Yes.

Q Would you agree that the Motion contained a few examples of issues that you identified in the Audit Report, but that the Audit Report itself was much more expansive, and had other issues that were brought up that weren't specifically mentioned in the Motion?

A (Moran) Yes. That's correct.

Q Okay. I'd like to talk a little bit further about two specific paragraphs in the Motion. One is Paragraph 27. Paragraph 27 talks about the utility's payroll, is that correct?

A (Moran) Correct.
Q And it goes on to say that the -- in summarizing the Audit Report, that the Audit Department was not able to determine that the payroll that was recorded by the Company, you weren't able to verify which accounts that payroll "ended up in", if that's the right term. Is that a fair assessment of that?
A (Moran) Yes. That's correct.
Q Could you explain a little bit further about what happened with respect to your analysis of the utility payroll, and how it was you weren't able to trace it to the various accounts?
A (Moran) One of my auditors was on-site with the Payroll Department, reviewing the actual payroll detail, and requested to which specific general ledger accounts the payroll data posted, and she was unable to learn that.
Q Okay. Could you just move a little bit closer to the microphone? I'm just having a little hard time hearing you.
A (Moran) Sorry.
Q No, that's better.
A (Moran) The auditor who did the work was on-site

doing that work. So, she reviewed all of the confidential payroll information, and tried to do a follow-up to ensure that the payroll dollars were posted to specific general ledger accounts. And the person with whom she was working couldn't tell her to what accounts those were posted.

Q And do you know what the reason was, why the Company couldn't provide that information?

A (Moran) Generally, from what I understand, a prior report that existed under Cogsdale and Great Plains hadn't been converted yet to some sort of similar report in SAP. So, the Payroll people were unable to tell her to what accounts they were posted.

Q And this report that you're talking about, this is something that had been available in past audits that you've done for Liberty?

A (Moran) Correct.

Q And it just wasn't -- wasn't able to be provided in this case, is that right?

A (Moran) Correct. But we understand that it could be a different kind of report in SAP. And it just wasn't available at that time.

Q Okay. Well, similarly, I'd like you to turn to

Paragraph 30 in the Motion to Dismiss. This paragraph talks about Corporate allocations from Liberty's parent company or upstream Corporate affiliates. And the conclusion in the Motion says that "it remains unknown how much of Liberty's Corporate allocated charges are included in the Company's revenue requirement and whether those charges are appropriate for recovery in Liberty's rates."

Could you give a little background as to what led me, who wrote the Motion, and to bring that out in the Motion to Dismiss, and how it is that the Department came to that conclusion?

A (Moran) Well, in a similar vein, we look at background data in an attempt to verify the details within that data to the respective general ledger accounts, which may or may not be part of the revenue requirement. And we were unable to do that.

Q And, again, do you know why you were unable to do that? Was there -- similarly, was there a report that had been provided in the past that was no longer available or --

A (Moran) I'm assuming there was a report that had been available in the prior system, and just hadn't been made available in the SAP system.
Q Okay.
A (Moran) Although, I would have to double-check with the auditor who did the work.
Q Sure. But the fact is that you stand by the conclusion that you were unable to make that determination in this case?
A (Moran) Correct.
Q Okay. So, you were present here at the January 4th hearing, were you not?
A (Moran) Yes.
Q And you heard a lot of discussion about "mapping issues" in connection with the conversion of the Company's accounting system from the old system to the new system?
A (Moran) Yes.
Q And just for some background again, you referred to the old system by what name?
A (Moran) Great Plains.
Q And the new system by?
A (Moran) SAP.
Q SAP, okay. Could you give a general

understanding of the "mapping issues" that we heard about on January 4th?

A (Moran) I'll try to summarize it for you.

Q Sure.

A (Moran) From what I understand, when the Company converted from Great Plains to SAP, all of the Great Plains activity was to roll into or be converted over to respective similar SAP accounts. And, within the conversion itself, some activity was mapped to the incorrect account.

I mean, that's the short, short version of what we encountered.

Q Okay. So, if you were here January 4th, you heard me say a number of times that, in many instances, you found examples where costs that should have been included on an income statement ended up on a balance sheet, or vice versa, accounts that should have been on a balance sheet ended on the income statement. Did you hear me say that a few times?

A (Moran) I did.

Q Do agree with what I was saying at the January 4th hearing?

A (Moran) I do. Those came out of our Audit Report.
Q And that's detailed in the Audit Report, correct?
A (Moran) Correct.
Q Okay. So, again, we started by asking how long you've been doing this, and your answer was "25 years", and you've worked almost exclusively on regulated utility audits.
How would you characterize the degree or the number or the significance of the mapping errors that you came across in this audit, versus what you found when examining the books of other companies?
A (Moran) This is very unusual. Occasionally, we find accounts that don't fit where they were allegedly supposed to be, like on the FERC Form 1 or on an annual report for a water or sewer company. But, even in this instance, looking back to the 13-063 audit, which we did, which was the National Grid-Liberty rate case audit, --
Q You're referring to a docket number, "DE 13-063"?
A (Moran) Correct. We did an audit. In that instance, there were six months of expenses and balance sheet for National Grid, six months for

Liberty, because they changed ownership on July 1st. And, while there were certain conversion issues in that instance, there just were far fewer.

Q Okay. How about any other companies that you've audited, after they have gone through a change of accounting system? Would you describe this as similar to those or was this one atypical?

A (Moran) This is atypical.

Q Okay. In terms of number of mapping errors and the significance?

A (Moran) Correct.

Q Okay. During the course of the audit, did you receive any information from Liberty that would indicate that the mapping issues that were identified have been corrected?

A (Moran) As I noted in the Audit Issue Number 1, the Company did say that, throughout 2023, as the issues were identified, the Company was working to correct those, either through journal entries or updating the treatment in their Work Breakdown System, the WBS. But I have no way of verifying if any of that took place.

Q Did you learn of any mapping issues being

corrected in 2022, because your last answer said "2023"? Did you learn of any corrections being made in 2022 from Liberty?
A (Moran) No.
Q Sorry?
A (Moran) No.
Q Have you done any independent audit work outside of what's contained in the report, looking into whether or not the mapping issues have been corrected?
A (Moran) No, not for Granite State.
Q Have you done any audit work in connection with Granite State on the books for 2023?
A (Moran) No. I hesitate, only because some of the annual audits, such as the RDAF, roll into '23, but not in this context.
Q Yes, I'm sorry. I should have said "with respect to the rate case that was filed", and the fact that the test year was 2023 **[2022?]**.

Have you taken any time or effort, or dedicated any resources, towards looking at Liberty's general ledger in 2023 concerning these mapping issues?
A (Moran) No, I haven't.

Q Okay. Do you have an opinion or any statements about what you think it might take for Liberty to identify, to be sure that they have identified all the mapping issues, and they have, in fact, been corrected?

A (Moran) I think it would be helpful to the Company to have an IT audit performed, to ensure that the literal translation from one system to another was done correctly. We don't have the expertise to do that.

Q Okay. During the course of the rate case audit that's contained in the report, that's summarized in the report, you reviewed the Company's FERC Form 1, correct?

A (Moran) Correct.

Q Typically, does the Company's FERC Form 1 -- do the amounts and the figures in a company's FERC Form 1 match what you find on the books and records of the company?

A (Moran) Yes, typically.

Q And, in this case, did you find that those matched?

A (Moran) No. Certain accounts certainly did match, but many did not.

Q And was that due to the mapping issues that we've been discussing today, and that were discussed on January 4th?
A (Moran) Yes.
Q And, if I recall your Audit Report, there were numerous entries that you had in the Audit Report, I estimated them at around 200 entries. And, in the Motion, those are characterized as "entries that would have needed to have been made to the books for the books to match the FERC Form 1."
A (Moran) Correct.
Q So, I'm just going to ask you, did I -- in the Motion, did I summarize that correctly?
A (Moran) Yes.
Q Okay. And, so, those 200 entries are laid out in the Audit Report, all the detail is there, is that right?
A (Moran) That's correct.
Q Okay. I'm hesitating as I ask this question, but let me ask it anyway. So, which, in your opinion, would be more accurate, the books or the FERC Form 1?
And I ask you that, because it sounds

like, to me, that there was an attempt to make a lot of correcting entries before the FERC Form 1 was completed.

A (Moran) And I'm hesitating in response, because, if you're trying to make the FERC Form 1 look as it should, then the FERC Form 1 is probably more accurate than the year-end SAP accounts, which we know were incorrect.

However, they're both supposed to be the same. So, I don't want to say one way or the other that they should have done one thing or another. They should have made sure the accounts were accurate at the end of the year.

Q Yes. Fair enough. But I do hear you saying that the -- for example, the accounts that maybe were -- should have been on the balance sheet, but ended up on the income statement, or vice versa, it appears to you anyway, or appears to the Department of Energy, that the Company attempted to correct those when they prepared the FERC Form 1. Would you agree with that?

A (Moran) They attempted to correct the placement on the FERC Form 1.

Q Okay. And I'll ask the Company's witnesses when they take the stand. I just wanted to bring that up with you.

In a rate case audit, do you typically compare the Company's rate case filing to its FERC Form 1 and its general ledger?

A (Moran) Yes.

Q And, typically, in a rate case filing, do those numbers all match?

A (Moran) Typically.

Q In this case, they did not match, is that right?

A (Moran) There were many that did not match.

Q Okay. And you highlighted those in your Audit Report, is that correct?

A (Moran) Yes.

Q Okay. And I believe I found them at Page 190 of your Audit Report, that's Bates Page 216 of Exhibit -- of Exhibit 8. And that information was also provided to the Commission as "Exhibit 4" at the January 4th hearing. Is that right? Those are some of the differences --

A (Moran) Correct.

Q -- that you found between -- well, differences that were identified between the rate case schedules --

A (Moran) Correct.
Q -- and the FERC Form 1?
A (Moran) That's correct.

MR. DEXTER: Okay. Well, thanks, Ms. Moran. That's the questions I had for you on direct.

I'd like now to turn to Ms. Nixon and Ms. Trottier.

CHAIRMAN GOLDNER: Attorney Dexter, quickly. There's two Bates numbers on Exhibit 8. Are you referring to the one to the far right or to the other?

MR. DEXTER: The number to the far right bottom corner are the Exhibit 8 Bates numbers.

CHAIRMAN GOLDNER: Okay. Thank you.

MR. DEXTER: So, I'm being told I had that backwards. So, the bottom right-hand number would be from the Motion to Dismiss. And the number to the left of that would be the Bates number from Exhibit 8.

CHAIRMAN GOLDNER: Okay. So, the page you were just referring to don't orient the Commission. I think you said "216"?

MR. DEXTER: I did. I might have had that backwards. Let me check.

CHAIRMAN GOLDNER: I think it was -- I think you meant "190". But maybe, let's see.

Yes, I think you meant "190".

MR. DEXTER: "190" would be the Bates Page number for the Exhibit 8.

CHAIRMAN GOLDNER: Yes.

MR. DEXTER: Apologies for that.

CHAIRMAN GOLDNER: Okay. So, just to orient us in the future, do you plan on orienting us to the Bates page number for Exhibit 8, is that --

MR. DEXTER: That will be my intent.

CHAIRMAN GOLDNER: Okay. Very good.

MR. DEXTER: Okay. Thank you.

BY MR. DEXTER:

Q So, Ms. Nixon and Ms. Trottier, I was going to ask you to refer to the Motion to Dismiss that was filed on December 13th. And I'd like you to look at Paragraphs 32 through 36.

These paragraphs detail some concerns the Department had with recording of revenues and billing determinants during the test year, is

that generally correct?
A (Nixon) Yes.
Q And, in particular, these paragraphs detail an inquiry that the Department made during the rate case about potential billing delays that occurred as the result of the implementation of the SAP system. Would you agree with that?
A (Nixon) Yes.
Q And have you reviewed those various motions -- those paragraphs, various paragraphs in the Motion?
A (Nixon) Yes.
Q And do you agree with the statements that are laid out in the Motion, concerning the issue of delayed billing due to SAP and the potential impact on test year billing determinants and revenues?
A (Nixon) Yes.
Q Okay. Do you have any information as to whether or not similar billing issues have persisted into 2023 and 2024?
A (Nixon) Yes. There was a data response that showed that some bills weren't actually issued until as late as August. And those are some that

the Company had identified. But I'm not sure if there's more than that.

Q That would be August of 2023?

A (Nixon) Correct.

Q Okay. And I'd like you to turn to Paragraph 38 for a minute. This has to do with "late payment charges". Have you reviewed that paragraph in the Motion?

A (Nixon) Yes.

Q And that paragraph essentially indicates that late payment charges were not assessed during the month of October, because of the SAP implementation. Basically, that's what that paragraph says, is that right?

A (Nixon) Yes.

Q Do you agree that, based on the review, that the Department has found that that's an accurate assessment?

A (Nixon) Yes.

Q Okay. Now, at the December -- I'm sorry, at the January 4th hearing, we heard from the Company references to a filing that they made on November 27th, we've referred to as the "Corrections and Updates Filing", and it's actually marked as "Exhibit 7" **[**Exhibit 6**?]** in this case. Have you reviewed that document?

A (Nixon) Yes, somewhat. But not in great detail to identify if all the corrections that were known have been made.

Q So, let me just unpack that a little bit. So, the filing came in on November 27th. And you filed testimony on December 13th. And did your testimony attempt to reflect the Corrections and Updates Filing, and the testimony of other witnesses as well?

A (Nixon) As we noted in our testimony, that we used that Updates, because we had to assume that it was better than the Initial, because the Company outlined some corrections they made. But we were not able to verify that all the corrections were made that were required.

Q Okay. So, in other words, you haven't been able to go back through all the various data requests where the Company noted, for example, "this will be dealt with in the Corrections and Updates Filing", you haven't taken the opportunity to cross-reference and make sure that the Corrections and Updates Filing captured

everything that it was supposed to, is that what you're saying?
A (Nixon) Correct.
Q Okay.
CMSR. CHATTOPADHYAY: Can I confirm whether it's "Exhibit 6" or "Exhibit 7" that you're talking about?
MR. DEXTER: Maybe the Company could confirm that. It's their exhibit, the Corrections and Updates Filing. I thought it was -- I thought it was "7", but --
MS. RALSTON: It is "6".
MR. DEXTER: Six. Sorry about that.
CMSR. CHATTOPADHYAY: Six?
MR. DEXTER: Yes.
BY THE WITNESS:
A (Dudley) Mr. Dexter, just to add to that, how the update occurred. It was a little unusual, in terms of our experience in other rate cases. Typically, what happens, with an update, is that our cost of service expert, Donna Mullinax, will go through the cost of service and determine which expenses are appropriate to include in the revenue requirement, and which expenses are not.

Those -- that information is passed on to the utility. The utility looks it over. And, then, typically, the utility produces an update, updating the revenue requirement, less the expenses that Ms. Mullinax had recommended come out.

Typically, that update is accompanied not only by the spreadsheet, which provides the adjustments that were made, but it also comes with a technical statement explaining those adjustments.

In this particular case, with Liberty, on November 27th, we were provided with just the Excel spreadsheets. We were not provided with a technical statement that actually described and detailed the accounting adjustments that were made.

The other distinction is that these were accounting adjustments, not adjustments to expenses and to adjust the revenue requirement. These were corrections to accounting entries that had been made incorrectly. And, because of that, they require verification, they require confirmation, as to whether or not they are accurate.

And, between the time of the filing, November 27th, and the filing of our testimony, on December 13th, there wasn't enough time to actually do that in-depth verification.

BY MR. DEXTER:

Q And I think you're trying to draw a distinction, if I understand, Mr. Dudley, between past cases where, you know, during the course of the examination, you've mentioned "expenses", and I assume it could be a rate base item, too, you might find something that was non-utility related that might get adjusted out of the cost of service, like maybe a charitable contribution or something like that that's not recoverable through rates, and that would be taken care of in the Corrections and Update filing, is that what you're saying?

A (Dudley) That is correct. Yes.

Q And here, what you're saying is, most of what was included in that spreadsheet that was provided were actually trying to bring the rate case up to -- I'm sorry, trying to correct the rate case for errors that were inherent in the books as

they were filed?
A (Dudley) Correct.
Q As they were closed at the end of 2022?
A (Dudley) Yes. That's correct.
Q Okay. Have you, at the Department, the four of you, been working on the rate case since the stay was issued by the Department *[sic]* on December 29th, 2023, other than preparing for this hearing?
A (Nixon) I was going say "preparing for this hearing". But that's it.
A (Trottier) No.
A (Dudley) Preparing for the hearing, yes.
Q And, in terms of the outside witnesses that the Department retained, did you instruct them to stop working on this case as of December 29th until further notice?
A (Nixon) Yes.
A (Dudley) Yes, we did.
Q Okay.
A (Nixon) I have one thing to add to the Corrections and Updates that you were saying, is the other thing is, as we heard last hearing in this case, there were additional corrections.

And those, obviously, were not included in that November 27th filing.
Q So, as I recall, the Department received a Supplemental Data Response 2-5 on December 6th, 2023, and that talked about a mapping issue. And we included that in the Motion to Dismiss as part of Exhibit 8. Is that what you were talking about?
A (Nixon) No. I was referring to -- well, there's that issue. But I was referring specifically to the errors that were mentioned at the last hearing, that we just had heard about at the last hearing.
Q Okay. So, let's take them one at a time then. And I think I have -- I think I have the wrong Bates numbers in my outline. So, that's why I'm hesitating a little bit.
CHAIRMAN GOLDNER: Attorney Dexter, while we're sorting through that one, I want to make sure we've got the whole thing together.
At the last hearing, you presented a handout. We had asked for that to be filed as "Exhibit 4". I think that you actually filed at least most of it in Exhibit 8. That's that

Page 190 we were talking about. But I don't see an Exhibit 4 that was filed from the Department. So, I was hoping you could help me?

MR. DEXTER: Sure. Sure. So, I guess I'm going to be a victim of the old-fashioned way. Because, in the old days, when you handed out the paper exhibit, and it went to the Clerk, who sat where Mr. Speidel is sitting now, that would take care of it. And that's, obviously, not the way it works in the electronic era.

So, I guess I did not file that Exhibit 4 electronically. But I will do that.

CHAIRMAN GOLDNER: Okay.

MR. DEXTER: And that was one of the data requests that we've been talking about.

CHAIRMAN GOLDNER: Correct. Correct. I just want to check in with the other parties to make sure there's no concerns. The handout, from the last hearing, filed as "Exhibit 4", Attorney Dexter will file that electronically, everybody is okay with that for this hearing?

[Multiple parties indicating in the affirmative.]

CHAIRMAN GOLDNER: Okay. Thank you.

MR. DEXTER: Yes. Sorry about that. Thanks for pointing that out.

BY MR. DEXTER:

Q So, Ms. Nixon, let's talk about the errors that were identified by the Company at the January 4th hearing. Those have been detailed in Record Response Number 1, is that correct?

A (Nixon) I am not sure if it's all of them. It identifies -- says that it's "some of them". But I don't know if it was all that they were referring to.

Q Okay. If we were to go to -- I don't know if you've got Record Response Number 1 in front of you, but there's a chart that details -- they were -- the Company was asked to list the various mapping issues in order of magnitude, starting with the largest, and ending with Number 10. Do you have that sheet in front of you?

A (Nixon) I pulled up the record request. I don't have the exhibit, but I do have the record request.

Q Okay. And you'll see that Item Number 5 -- sorry, Item Number 1 -- let me rephrase that. You'll see that Item Number 5 is dated

"December 2023". And there's a footnote that pertains to items number "5, 8, 9 and 10". It's your understanding that those were the errors that were identified by the Company at the January 4th hearing, correct?
A (Nixon) That's my understanding. But, as I noted, I know that -- I mean, this list, it's my understanding it's the top ten in dollar magnitude. So, I don't know if that encompasses all that they were referring to.
Q Sure. Yes. There could have been number -- 11 through 20 could have --
A (Nixon) Exactly.
Q Yes. Okay. I understand. All right. Mr. Dudley, I'd like you to go to the Motion to Dismiss that was filed, to Paragraph 40, appears on Page 16 of the Motion.
A (Dudley) Okay. Let me just get there, Mr. Dexter.
Q Sure.
A (Dudley) And, okay. Yes, I'm there.
Q So, that paragraph has to do with Vegetation Management expenses that are included in the rate case for recovery, is that right?

A (Dudley) That is correct. Yes.
Q Have you reviewed Paragraph 40?
A (Dudley) I have, yes.
Q And are you in agreement with the conclusions that are stated in Paragraph 40, that the amount for Vegetation Management included in the rate case has been updated at least twice by the Company in this case?
A (Dudley) Yes. I agree.
Q And is it your understanding that in this -- well, I'm going to strike that question.
I guess I have a question for the panel, and anyone can answer that thinks that they have the answer, or feel free to supplement each other's answers. But, at the January 4th hearing, we heard a proposal by the Company that, rather than dismiss the case, as the Department of Energy requested in the Motion, that the case be put on hold while a third party auditor be hired to review the underlying books in the rate case, and to make sure that they're all corrected, and then the case go forward.
At the January 4th hearing, I stated, on behalf of the Department, that we didn't think

that was the appropriate remedy in this case. Do you have any additional thoughts on the suggestion that this case be paused, and that it be turned over to a third party auditor?

A (Dudley) Well, Mr. Dexter, it's based on what we know and what we don't know. What we don't know are the specific details of Liberty's proposal. We know that they recommend extending the stay for an additional 90 days, so that the audit can be completed. We know that Liberty would like to be the ones to choose the auditor. And that, preferably, that auditor has an existing business relationship with Liberty.

We also know that they prefer that the audit -- that the audit just be targeted to the correction issues associated with the 2022 test year and the mapping issues. That's as much as we know.

We were informed by counsel for Liberty, at the January 4th hearing, that errors continue to be found in the mapping. And, as a matter of fact, counsel represented to the Commission that the Company had recently identified some additional adjustments related to the 2022 FERC account mapping issues, and that that would lead to a flow-through of an additional update to the revenue requirement. So, apparently, an additional update is forthcoming to the update that was issued on November 27th.

And, so, the question we have is that, if an additional update is forthcoming, because Liberty continues to discover errors in its mapping, is there going to be a third update? Is there going to be a fourth update? Is there going to be a fifth update? We don't know.

What we don't know is, and, as Ms. Nixon alluded to earlier, we don't know the extent of the errors. We don't know the full extent of the errors.

Q Okay.

A (Dudley) We only know about those errors that have been discovered.

We think that the test year has been sufficiently tainted beyond repair. We don't think that -- we believe that an audit, which, by the way, should have been done by Liberty, should have been performed by Liberty, before they filed

their rate case, we think it would be a waste of time and resources.
Q So, let me just follow up on that. I know Ms. Nixon wants to chime in. But, along what we do know, we do know that the conversion took place in 2022, is that right?
A (Dudley) Yes. That's correct.
Q And we do know that the books in 2022 were not corrected in 2022, but all the various mapping corrections were done starting in 2023, is that right?
A (Dudley) That's correct. And our understanding, again, from counsel's representation, is that, as errors continue to be discovered, that those corrections will carry over into 2024.
Q Okay. I just wanted to clear that up. Yes, Ms. Nixon, did you want to add something?
A (Nixon) That was one of them, that there's still errors. And the books won't match.
But I also wanted to note that the Company did state that the external auditors had reviewed the books and were okay with it, according to what indication we got from the Company. So, they have already had auditors that

reviewed, but did not find these errors, and especially the mapping errors. And I don't believe that a typical auditor would be looking at IT issues, is my understanding.

Q And, so, then, as a panel, your recommendation would be that the Commission grant the Motion to Dismiss, rather than go down the third party auditor route, is that a fair assessment?

A (Nixon) Yes.

A (Dudley) Yes.

A (Trottier) Yes.

A (Moran) Yes.

MR. DEXTER: Okay. Thank you. That's all the questions I have.

CHAIRMAN GOLDNER: Okay. Thank you. We'll move to cross, beginning with the Office of the Consumer Advocate.

MR. KREIS: Thank you, Mr. Chairman.

I'm just going to ask a few questions. And I apologize in advance if any of them sound like they're intended as trick questions or hostile questions, because they're really not. I'm really just trying to figure out how we, at the Office of the Consumer Advocate, got here, which is an unusual place.

And I think I'm going to start with Ms. Moran.

CROSS-EXAMINATION

BY MR. KREIS:

Q Ms. Moran, I have to say that, even though you and I arrived on the scene here I think right about at the same time, in 1999, --

A (Moran) That's correct.

Q -- and, so, therefore, I have been acquainted with you since then, I know relatively little about what you actually do. And, so, I'm just going to ask you a few questions, just to make sure I'm understanding the significance of your audit correctly.

First of all, could you compare the actual process that you undertake when you do an audit like this, you and your team, obviously, to the sort of financial audit that a CPA firm would do of a non-regulated business, in order to make sure that their annual books accurately reflected the state of the company's finances at the end of whatever its tax year is? Is it basically the same process that you do?

A (Moran) Don, I can't actually say for certain, because I've never worked for a CPA firm. However, the focus of a regulator audit is, first and foremost, compliance with the Chart of Accounts make sure your general ledger agrees with your annual report, in this case, the FERC Form 1. And, then, we verify those to the Rate Filing.

That's the very first step in any audit that we do. Doesn't matter if it's a large utility or a small sewer company.

After that first step, we look into the activity within each account, to ensure that the entries in those accounts should be where they are. That's, in the world's smallest nutshell, that's what we do. But we verify things to source documentation, revenue, we tie to individual customer accounts, just to do what we call a "tariff test", to make sure that what they're authorized to charge they're literally charging to individual customers.

And we also look at, you know, payroll in general, revenues in general, expenses in general, do a comparison of year-over-year for income statement related items, make sure things that should be below the line are booked there.

Does that help at all?

Q Yes, it does?

A (Moran) Okay.

Q Is there any place in the audit that you completed in October that states what your -- the audit team's ultimate conclusion is, as to the accuracy of their representations you looked at in the Company's books and records?

A (Moran) You don't typically do that sort of conclusion that you would see in a regular CPA audit of financial statements or shareholder representation. The fact that there are so many issues at the end is kind of a conclusion.

We did say, at the outset of the audit, that we weren't able to get into as many details as we typically would, because we had trouble getting answers in a timely manner. That hindered us a little bit.

But, no, we don't typically do that.

Q So, in other words, if I understand your answer correctly, if I wanted to really kind of look at your audit and interpret it, I guess, the place

that I would look would be the 28 audit findings that come at the end of the audit, true?
A (Moran) That's true.
Q What is an "audit finding" exactly, as that term is used in the audit?
A (Moran) Well, an "audit issue", it's not an "audit finding".
Q Oh, excuse me. "Audit issue".
A (Moran) An "audit issue" is some instance where we found some kind of error, or misapplication of FERC rules, or misplacement of accounts or mismapping of accounts, that kind of thing. It's really just some error that jumped out at us as we progressed through our audit.
Q And I want to make sure I understood your earlier testimony. You mentioned that you provided the Company "a draft of the audit on October 9th", and then you said you "met with the Company on October 12th." And I just want to make sure I'm leaping to the right conclusion.
At that October 12th meeting, you discussed with the Company those 28 audit findings, correct?
A (Moran) We discussed whatever they wanted to

discuss. It's a very open process. Until the audit is finalized, the Draft Audit is only between the Audit Division and the Company. So, we can go back and forth a few different times to go over certain things, if we've misinterpreted something, or if they provided documentation that they hadn't when the Draft was originally issued. We can change the report, so the final document is cleaner and clearer.

Q Would that potentially result in you wiping out an audit issue altogether, because you were convinced by the Company that that issue had been resolved to your satisfaction?

A (Moran) It could.

Q Did that happen at all in this case?

A (Moran) I frankly don't recall.

Q In the audit issues that you identify, there are different places where the Company indicates that it basically agrees with the concern that you expressed, and it made certain commitments around how it would deal with correcting those issues that you identified. That's pretty typical, isn't it?

A (Moran) That is typical, yes.

Q Did the Company, in fact, follow through and do the things that it said it was going to do in its response to your audit issues?

A (Moran) I think there were only two issues that we asked for copies of updated journal entries. But the other issues, we wouldn't do any kind of follow-up audit work until the next rate case audit.

Q And, with regard to the sheer number of audit issues that you identified, 28, can you put that in perspective? Is that a lot of issues? Is that not a lot of issues?

A (Moran) For a rate case, that's fairly typical. But the detail of each issue is really what's the reason we're here.

Q Thank you. So, that's very helpful. So, what you're suggesting that I do, and, ultimately, what the Commissioners do, is not make a decision based on the number of audit issues, which I think you just said is not that unusual, but, really, your concern as an auditor has to do with the magnitude of and the significance of some, maybe all, of those individual audit issues that your team identified?

A (Moran) That's correct.
Q Thank you. That's so helpful. I really thank you for -- I'm sorry for asking you questions about things I should probably have long ago learned the answers to, but I didn't.
Okay. I think, now I have a couple of questions that might be for Ms. Nixon, or Mr. Dudley, or Ms. Trottier. I guess I don't -- whichever one of them or ones of them want to answer will be helpful.
Let me start with Ms. Nixon. Ms. Nixon, you're aware that our Office filed testimony in this rate case on the same day that you and your team filed your testimony, yes?
A (Nixon) Yes.
Q Have you had a chance to review the testimony that we filed at the OCA?
A (Nixon) No.
Q So, you haven't read it?
A (Nixon) No.
Q If I told you that none of the testimony we filed, and, in particular, the testimony that Mr. Defever filed, who is, I think, the counterpart to your Witness Mullinax, if I told

you that his testimony doesn't raise any of the issues that you're here raising today, would that -- like, what do you make of that?
A (Nixon) Well, I guess I would -- I mean, I'm jumping to conclusions, but you asked me to hypothesize.
Q Yes.
A (Nixon) So, I would say that, based on that person's experience, that you don't have to deal with the issues we're dealing with here. So, you have to assume everything is accurate to the best of your knowledge, and proceed forward like you normally would in a rate case.
Q Right. That's really helpful, because that's exactly what I didn't intend to be a trick question. I just want to make sure that the Commission understands that the fact that our testimony doesn't raise any of the same issues that you all are raising isn't -- doesn't mean that, in the judgment of the OCA or its witnesses, the Motion to Dismiss is without merit. Is that a fair statement, from your perspective?
A (Nixon) Yes. I mean, we had to make similar

assumptions. I mean, we proposed the dismissal. But, if the decision is to not dismiss this case, we had to move forward and use numbers that we had.

MR. KREIS: And I think those are all of my questions. Thank you.

CHAIRMAN GOLDNER: Thank you.

We can now move to Dartmouth College, and Attorney Getz?

MR. GETZ: No questions, Mr. Chairman.

CHAIRMAN GOLDNER: Thank you.

We can now turn to the Company, and Attorney Ralston?

MS. RALSTON: Thank you. Good morning to the panel.

I have a series of questions that I have tried to break up by topic. So, I'll pose them to the panel kind of generally. A few of them may be more pertinent to one witness or the other, and I'll try to indicate who I think is the right person. But please correct me, or, you know, jump in.

BY MS. RALSTON:

Q So, first, I'm just going to direct the entire panel to the Motion to Dismiss, at Paragraph 6. So, in Paragraph 6, it states that "even if all factual assertions in the Company's Rate Filing are taken as true, the unreliability and inconsistency presented throughout Liberty's filings and the inferences to be drawn from this unreliability do not support Liberty's requested rate relief." Do you all see that?

A [*Multiple witnesses indicating in the affirmative*].

Q Okay. And does the panel agree that, prior to the filing of this Motion to Dismiss, that the Company had submitted its Initial Filing, which included testimony, supporting exhibits, and that the Company has also provided an updated revenue requirement, we've been discussing that this morning, it's marked as "Exhibit 6"?

A (Nixon) Yes.

Q Okay. And does the panel also agree that the Company has responded to a number of data requests as part of the proceeding, and then also to data requests issued by the Department's Audit Division?

A (Nixon) I'll speak to the ones from Regulatory, yes. I don't know about Audit.

Q And do you agree, Ms. Moran, that the Company responded to specific data requests from the Audit Division that were used to develop the Audit Report?

A (Moran) The Audit Division doesn't issue data requests. But they did respond to our audit questions.

Q "Audit questions", maybe that's the right term. Apologies.

And, then, could each member of the panel indicate what you reviewed prior to preparation for today?

A (Nixon) Basically, the issues at hand. The Motion, the Motion was the main thing. But there's various other documents, rules, testimonies. And I can't list them all. But, yes. Just general hearing prep.

Q Okay.

A (Trottier) I mainly just reviewed the Motion, and the --

[Court reporter interruption.]

BY THE WITNESS:

A (Trottier) I mainly just reviewed the Motion, and the references within it.

A (Dudley) For me, it would be all of the exhibits, some of the testimony, in particular, the Audit Report and the Motion.

A (Moran) The same.

BY MS. RALSTON:

Q And I think that, Ms. Moran, I think you confirmed this just a few minutes ago, actually, but am I correct that you are the only witness that participated in the audit investigation and preparation of that report?

A (Moran) That's not correct.

Q That's not correct. Okay.

A (Moran) No. The entire Audit Staff participated in writing the report, including me. But, as the Director, I oversaw the completion of it.

Q Apologies, maybe I wasn't clear. Are you the only witness on the stand this morning, though, that --

A (Moran) Yes.

Q Okay. That's all I just wanted to confirm.

Okay. So, I'm going to direct you, Ms. Moran, through a series of questions as you're -- due to your involvement with the audit investigation.

So, going back to the Motion to Dismiss, at Paragraph 17, it states that the Audit Division was unable to perform its work efficiently "due to the significant timing delays between asking questions of Liberty and receiving responses." Do you see that?
A (Moran) I do.
Q Okay. And what is the typical turnaround time for a utility to respond to a question from the Audit Division?
A (Moran) It can be anywhere from hours, to a few days.
Q Okay. And is that turnaround time set in a regulation or is it --
A (Moran) No.
Q -- established by a procedural schedule?
A (Moran) No. We're not usually part of a procedural schedule. It's simply the way the audit functions.
Q And, if we can turn to Exhibit 8, which is the Audit Report, at Page 149, which I think correlates to 175 in the Motion, if you're getting confused with the Bates numbers, I know there's been a little confusion.

It states that "Because of the quantity of noted adjustments, and the time required to identify variances among the FERC Form 1 accounts, Audit is unable to determine if the reported adjustments are accurate nor if they represent all of the adjustments that should have been done." Do you see that, Ms. Moran?

A (Moran) I'm not there yet, but I recall the statement.

Q I can let you get there, if you would like.

A (Dudley) I'm sorry, Ms. Ralston. You said that's "Bates Page 175"?

Q It's Bates 149, but I think, in the Motion attachment, it was "175". I was just trying to give the two numbers to help with --

A (Moran) I think that's opposite.

Q And, so, Ms. Moran, is the Audit Division's investigation timeline governed by a Commission rule?

A (Moran) No.

Q And is the Audit's investigation timeline governed by the procedural schedule?

A (Moran) No.

Q And did the Audit Division request any additional

time, in light of the challenges it faced?
A (Moran) I don't understand the question.
Q Did the Audit Division request any additional time to perform its investigation?
A (Moran) No, I heard the question. I just don't understand the question. Sorry.
Q So, the statement from the Audit Report says that "due to time constraints" you were unable to verify the accuracy of the information. And, so, I'm just asking if you asked for more time?
A (Moran) Okay. The answer is "no."
Q Okay. The Company converted to the SAP system during the 2022 test year. Is that your understanding?
A (Moran) Yes.
Q Okay. Do any other New Hampshire utilities use an SAP accounting system?
A (Moran) I'm unsure.
Q Okay. Would you agree that an SAP accounting system would require different audit processes than other types of accounting systems?
A (Moran) I disagree.
Q You disagree. Okay.
A (Moran) The Audit Staff works with many different

kinds of accounting systems across the various utilities.

Q If I refer you back to the Audit Report, at Bates Page 171, this is where the Audit Report addresses Audit Issue 13. And the audit issue states that "Prior to the switch from Great Plains to SAP, the Company used an Opex Capex report to reconcile the payroll to the general ledger." And that report is no longer available with the change to SAP, and I think you talked about that with Attorney Dexter. Do you see that?

A (Moran) That's correct. I'm there.

Q Okay. And, then, the related audit recommendation states that "reconciling the general ledger is an important step in providing accurate account details, and Audit recommended that the Company prioritize a replacement report."

In response, the Company confirmed that "Payroll is reconciled to the general ledger on each pay date." Do you see that?

A (Moran) I see that.

Q Okay. Is it your opinion that the Company must continue to produce information in that same format, even when the format is no longer available because of the system conversion?

A (Moran) Of course not. We just need to be able to verify, as I said earlier, in this instance, the payroll dollars to the general ledger system, regardless of what the system is. And we want to use the reports that the Company uses. We never want a report to be created just for us.

Q And just to clarify, Audit Issue 13 didn't result in any recommendations of a disallowance, is that correct?

A (Moran) Correct.

Q Okay. So, is it your opinion that the Company's payroll costs should be included in the revenue requirement that's used to set rates?

A (Moran) I can't say, because I don't know in what accounts they're posted.

Q I would like to continue referring to the Audit Report, but direct your attention to Audit Issue Number 1, which begins on Bates Page 139.

And Audit Issue 1 spans several pages. I think it goes between Bates 139 and 148, and lists a number of adjustments that were made by the Company. Do you see those?

Yes. It's on Bates 165, if you're using the Motion version.

A (Moran) I'm there.

Q Okay. And is it your understanding that those adjustments were made by the Company during its preparation of the FERC Form 1 and the revenue requirement schedules that were included in the Initial Filing?

A (Moran) I'm unsure if the adjustments were done. Those were the adjustments that were identified by the Company.

Q So, to rephrase, is it your understanding that those adjustments were identified during preparation of the FERC Form 1 and the revenue requirement for this filing?

A (Moran) My understanding was they were identified -- some were identified during the preparation of the FERC Form 1. Some were probably, and I don't know for sure, identified after, as the revenue requirement schedules were prepared.

Q But, to clarify, they were identified prior to filing this case? I think that's what you just

said, is that correct?
A (Moran) Parts of them were. As we know, there have been others identified recently.
Q Right. But I'm speaking specifically about Audit Issue 1. These were identified by the Company prior to filing this case?
A (Moran) Correct.
Q Okay.
A (Moran) Not all, though, just to be clear.
Q I'm sorry. Can you repeat that?
A (Moran) Not all, just to be clear.
Q Your statement is that not all of the adjustments in Audit Issue Number 1 were not, were identified before the filing?
A (Moran) I'm saying some of them were identified by Audit. Most were identified by the Company. But there were others that we asked about, and the Company agreed that they were mismapped.
Q Okay. And we're, just to be absolutely clear, we're both talking about Audit Issue Number 1?
A (Moran) Correct.
Q Okay. Thank you. All right. And, now, if I can turn you to the Company's Objection to the Motion to Dismiss, on Page 10. Do you have that

document in front of you?
A (Moran) I do not.
Q Okay. I will summarize. And, so, in that, in its Objection, the Company explained that it is not unusual to identify and make adjustments after the fiscal year accounting closing for the subsequent year. Do you recall the Company saying that or have you heard the Company represent that?
A (Moran) I've heard that represented.
Q Okay. Is it your position that the Company should have reopened the 2022 books?
A (Moran) No.
Q Okay. So, turning back to the Audit Report, in addition to Audit Issue Number 1 that we just discussed, there are 27 other audit issues, correct?
A (Moran) Correct.
Q Okay. And would you agree that some of those audit issues have resulted in recommendations for minor adjustments? So, for example, I could turn you to Audit Issue Number 2, which is on Bates Page 151, which recommends the removal of "$1,413"?

A (Moran) That's correct.

Q Okay. And would you also agree that certain audit issues represent a reasonable disagreement between the Audit Division and the Company that could be resolved during the proceeding? So, for example, Audit Issue Number 3, which is on Bates Page 153, relates to capitalizing fleet and equipment depreciation, and the amount at issue was $26,000, and the Company cited to a GAAP standard in support of its position. Do you agree that there could be a reasonable disagreement between --

A (Moran) I understand that we disagree. I don't think it's reasonable. FERC says you can't do that. So, we're on -- we're just on opposite sides of this one. You can --

Q Fair. And do you agree that the Commission could review Audit's position and the Company's position, if we move forward with the proceeding, and they could make a determination?

A (Moran) Sure. The Commission can look at whatever they choose to review.

Q And would you also agree that certain audit issues could be resolved through the exchange of additional information? So, for example, Audit Issue Number 4, which appears on Bates Page 155, states that, while Audit concurred with the Company's proposal, it did request the adjusting journal entries, which I think you referenced a few minutes ago as well. So, would you agree there are instances where additional information could resolve an issue?

A (Moran) There will always be instances where additional information could be provided. But this is now in October of 2023, that's not going to change the result of the 2022 test year review.

Hopefully, if we come back and do an audit in your next rate case, this issue won't exist.

Q And would you agree that certain audit issues did not result in any adjustments to the Company's revenue requirement, but were recommendations for improved processes going forward?

A (Moran) Yes.

Q Okay. Thank you. And, then, turning back to the Motion to Dismiss, and I apologize for making you flip between documents, at Paragraph 15, it states that "Since the source of the information contained in the Rate Filing and the FERC Form 1 and" -- hold on, I mistyped this. So, give me a second just to get there.

So, it states "Since the source of the information contained in the Rate Filing and FERC Form 1 is the Company's general ledger, all three pieces of information should match." Do you see that?

A (Moran) I see that.

Q Okay. And the Department of Energy's position is that the general ledger should always match the FERC Form 1, is that correct?

A (Moran) We understand there will be adjustments. In this instance, there were so many errors. I, as you now know, I've been doing this kind of audit work for a long time. I have never seen so many errors in the general ledger, versus the FERC Form 1, versus the Rate Filing.

Q And the Company has acknowledged, right, that there is a variance between the three sets of data. Do you agree that the Company has provided explanations for this variance?

A (Moran) I can't be certain.

Q If you turn to the Audit, back to the Audit Report, at Page 149, it states that "subsequent to the parent company closing of the books for the 2022 year-end, Liberty identified "Unadjusted Differences" of approximately 848,000." And, then, also on the same page, it says that "With the Unadjusted Differences reflected in the revenue requirement, the FERC Form 1 maps directly to the data recorded in Liberty's financial system. The Company has provided a trial balance to Staff that provides the direct mapping to the FERC Form 1." Do you see that?
A (Moran) I'm there.
Q Okay. And, so, is it your position that, even if the data can be traced to the financial records, it cannot be relied on?
A (Moran) The data can't be traced to the accurate financial records. A mapping of the mismapped issues is almost circular. I understand the Company acknowledges that there were mapping issues. But to say "we provided a listing to show what those mismapped things were" does not correct those issues.
Q Okay. So, going to Page 139 of the Audit

Report -- actually, I'm going to skip that one.

So, just one follow-up. I think a few minutes ago we discussed whether or not the Company should have reopened the 2022 books. And I think you said it was not your position that the 2022 books should have been reopened. Is that -- is my memory correct?

A (Moran) That's correct.

Q Okay. So, if the Company was not going to reopen the 2022 books, and the Company has provided an explanation for why the FERC Form 1 and the revenue requirement schedules do not match the 2022 books, wouldn't you agree the Company has provided an explanation for how it got from the 2022 books to what has been filed in this case?

A (Moran) Sure. It, again, doesn't clear the fact that the books are incorrect. They should have been cleared and adjusted during the close of year-end 2022. But I'm guessing, and probably incorrect to do on the stand, but I'm guessing that, simply due to the massive amount of mismapped accounts and entries, it couldn't be done. The books still have to be closed somehow. And your externals didn't want to reopen the books either, because, from the Corporate perspective, New Hampshire's Granite State Electric simply isn't big enough to reopen the SEC filings and federal filings. That's my understanding.

Q So, is it your position that the difference that exists between the rate case filing and the Company's books and other forms require the Commission to deny a request for a change in distribution rates?

A (Moran) Based on the audit work, yes, I agree with that statement.

Q In your opinion, should a utility make necessary adjustments prior to filing a rate change request to ensure the accuracy of the data?

A (Moran) The data should be verified for accuracy with each close, with each monthly close, with each annual close, with each quarterly close. Yes, I agree with that.

Q Right. But, if the Company does a review prior to a filing, and discovers additional adjustments are necessary, should it make those adjustments before it files?

A (Moran) If the books are already closed, no. But they should disclose all of those adjustments, as Mr. Dudley said earlier, disclosed in a technical statement of "These are the books, these are the revenue adjustments." And I'm not sure that's taken place here.

Q In your opinion, how much can a utility's rate case filing differ from its books and records without requiring a denial of the request for a change in rates?

A (Moran) I have no opinion on that. This is the first time we've ever seen books this far off. So, I can't quantify a dollar amount.

Q And, similarly, you couldn't quantify the number of adjustments?

A (Moran) Of course not.

Q And are you aware of the statutory language that describes what a rate case filing must be based on?

And I -- the entire panel is welcome to weigh in. I don't know if this is really Ms. Moran's area of expertise. So, acknowledging that. And I am referring specifically to RSA 378:27 and 378:28, where there's reference to setting rates based on reports that the utility has filed with the Commission and the Department of Energy.

Are members of the panel generally familiar with that statutory language?

A (Dudley) I am familiar with that, yes.

Q Okay. And would you agree, and I'll point to you, Mr. Dudley, that a FERC Form 1 is a report filed with the Commission?

A (Dudley) It is. Although, the Initial Filing from Liberty did not contain the FERC Form 1.

Q Right. But the Company filed an updated Initial Filing that did reference the FERC Form 1, correct?

A (Dudley) Correct.

Q Okay. And I think that's why we're using it as the basis for this case at this point.

And the Company's revenue requirement can be tied to the FERC Form 1, do you agree?

A (Dudley) That's typically how it's done, yes.

Q And, in this case, would you agree that the two documents can be tied?

A (Dudley) They can be tied. But, as we have discussed and have found out that the two don't match.

Q	Right. That's why I said "tied", I didn't say "matched". I think we provided explanations for why there are differences. But I'm just asking if they could be tied, if you can trace the differences?

A	(Dudley) I would say, ordinarily, you can. But I would defer to Ms. Moran.

Q	Ms. Moran, do you want to add anything?

A	(Moran) Well, I was concerned about one entry that was a revenue amount that was reflected in I want to say the "accumulated depreciation schedule", that's -- I could be wrong, but it wasn't in the revenue section. Actually, it was in the depreciation expense revenue requirement filing. And it was correctly proformed out of that, but it was not proformed back into the revenue schedule. And that's just one instance I remember off the top of my head.

As we said, because of the billing issues, and the different problems that existed with the customer service side of the business, I'm not sure -- I understand that the revenue requirement schedule does have certain revenue accounts that could be verified.

Q Okay.
A (Nixon) May I add to that?
Q Sure.
A (Nixon) So, the filing requirements and the FERC Form 1 do not match. And the Company did not highlight and identify those in their filing how they do not match.
Q But has the Company been able to provide explanations for that during the course of the proceeding?
A (Nixon) Through us identifying the differences, several of them, the Company did respond to a data request. But those were not -- an updated filing was not provided to indicate what those differences are, as required by those statutes and rules that are out there.
Q I am going to turn the panel to Exhibit 6, which is the Company's updated revenue requirement filed on November -- or, submitted on November 27th. And I think the panel, or at least some members of the panel, have reviewed it, if not in great detail.
But, if I could just refer you, there's a tab, I believe it's the very first tab of the

Excel version, and the title of that tab is "TrackRRUpdates"?
A (Dudley) Ms. Ralston, are you referring to Tab "RR-1"?
Q No.
A (Dudley) Because there are two Excel spreadsheets that were filed.
Q Yes. And I'm referring to Part - Exhibit -- "Part 2 of 3" of Exhibit 6. And, if you're in that Excel -- are you in that Excel filing, Mr. Dudley?
A (Dudley) I am, yes.
Q Okay.
A (Dudley) But I see the tabs are identified by "RR".
Q If you go all the way down to the bottom, the little arrows in the lower left-hand corner, and you go all the way over to the very first tab, there should be a tab that's called "TrackRRUpdates".
A (Dudley) Yes. I have it. Thank you.
Q Okay. Great. You and I have the same Excel skills.
So, would you agree that there are 25

adjustments that the Company included in this update that tied either to a specific audit issue or a data request?

A (Nixon) The list there shows that there were 26 issues identified.

Q Okay.

A (Nixon) I'm not looking at the exhibit. I'm looking at the original Corrections and Update. Did it change?

Q It didn't change. I would say I miscounted.

But, for me, it starts on Row -- well, so, Row 7 are the updates that were included in the original filing. And I may not have counted those.

A (Nixon) Okay.

Q Does that make sense?

A (Nixon) Yes.

Q And, then, it goes down to --

A (Nixon) I was looking at the --

Q -- Row 32.

[Court reporter interruption - multiple parties speaking simultaneously.]

CONTINUED BY THE WITNESS:

A (Nixon) I was looking -- I was looking at the reference number.

BY MS. RALSTON:

Q Yes. Apologies, I wasn't clear. Do you agree that utilities routinely submit updated revenue requirements as part of a rate case?

A (Dudley) They do. But, as I said earlier, Ms. Ralston, associated with expenses that are either included above or below the line.

Q And, so, I think you stated earlier, Mr. Dudley, that this -- you believe this revenue requirement update is unusual, and you wouldn't consider this typical?

A (Dudley) It's not typical from what we've seen, because it's largely accounting adjustments to accounting errors.

Q And your opinion is based on -- what is your opinion based on, that this is an atypical adjustment?

A (Dudley) I've never seen one like this.

Q Is it your position that the Company's adjustments to the revenue requirement included in the November 27th Update were improper or inaccurate?

A (Dudley) We don't know about the accuracy. We haven't been able to determine the accuracy. What we do know is that, based on counsel's representation on January 4th, that apparently there's another update forthcoming.

Q Right. And that would be a separate adjustment.

A (Dudley) But we don't know that.

Q But you don't -- right. But you're not taking a position, I guess is what you're saying, on whether or not the adjustments that have already been made were improper or inaccurate?

A (Dudley) Our position is that we need -- we would need an opportunity to study those to determine whether or not they are accurate. And we'd have to perform confirmation and verification.

Getting back to the typical rate case, and the typical update, regarding expenses above or below the line, those are known and measurable. These amounts here that I'm seeing, I don't know whether or not they are known and measurable. I have nothing to check them against. So, it would require an in-depth review that the Department didn't have an opportunity to perform.

And, again, this is unusual. We

typically don't deal with numerous accounting adjustments to correct accounting errors in an update. We also are typically provided with a technical statement that describes in detail each adjustment that's made. These are just cursory notes that I'm looking at right now that don't really provide any detail.

Q But you do acknowledge the Company included that first tab that explained the basis for each of the adjustments, and then together -- and there was a filing letter, I believe, that explained what the Company had included with this update? Would you agree with that?

A (Dudley) I agree that there's a one-page filing letter.

Q Is it the panel's position that the Company's FERC Form 1 was not accurate at the time it was prepared?

A (Dudley) You want that one?

A (Moran) Yes. I can address that one for you. I can say that the map that was provided tied the SAP year-end figures to the FERC Form 1. I cannot say if those entries were accurate.

So, no, I can't say that the FERC

Form 1 was accurate.
Q And that, what is that based on, your -- is that based on your audit investigation?
A (Moran) Correct.
Q I now have a few questions related to customer billing issues. And I'll just open these up to the panel.
In the Motion to Dismiss, the Department of Energy stated that "Implementation of SAP had Resulted in Significant Customer Complaints to the Department". And does the panel see that section of the Motion that begins on Page 20?
A (Nixon) Which item number are you referring to?
Q I am referring just generally to Section VII of the Motion that begins on Page 20, regarding customer complaints.
Okay. And, then, on Page 1 of the Motion to Dismiss, the Department of Energy is arguing that the case must be dismissed because "the 2022 financial information on which the Rate Filing is based cannot be reasonably relied on and therefore Liberty has not and cannot meet its burden to provide *[sic]* that the proposed rates

are just and reasonable." Do you also see that on Page 1 of the Motion?

A (Moran) Yes.

Q Is it the Department's position that the Company's financial information is the cause of the increase in customer contacts with the Department?

A (Nixon) I believe, as indicated in DOE witnesses, yes, there was -- there have been a significant increase in customer contacts with the Department.

Q And is it your position that those are related to the financial information that we've been discussing, the unreliability of the financial information?

A (Nixon) Yes, some of them, a significant amount. In fact, a study -- a survey done by the Company -- or, that's done independently, confirmed that as well.

Q Confirmed --

A (Nixon) It's not contacts with the Department, but that there was customer dissatisfaction because of this system.

MR. DEXTER: Mr. Chairman, if I could

interrupt? We didn't name Amanda Noonan as a witness. Amanda Noonan is the Director of the Consumer Services Division at the Department. And she is familiar with the issue of customer contacts and the customer survey results that Ms. Nixon just identified.

So, I wonder, I don't know how much questioning, we didn't know this was going to be an issue today, but Ms. Noonan is available to answer these question, if that's appropriate?

CHAIRMAN GOLDNER: Does the -- would the Company like to put Ms. Noonan on the stand?

MS. RALSTON: I don't know if it's necessary. I guess it depends on whether or not the Department of Energy intends to support its Motion using customer complaints.

I think that, on Page 1, they're arguing that the Motion is based on the financial records. And, if the Department agrees the financial records are not related to the alleged increase in customer complaints, we don't need to go further.

CHAIRMAN GOLDNER: Attorney Dexter.

MR. DEXTER: No, I think we're -- our

point is the opposite. That the implementation of the SAP system included a billing system and an accounting system, and that the implementation of the billing system went poorly, and resulted in increased customer complaints and a decrease in customer satisfaction, as laid out in the Luth survey that was provided with the Motion.

So, we believe that they are interrelated.

CHAIRMAN GOLDNER: So, let's do this. Let's put Ms. Noonan on the stand, so that we can -- we can reach closure on that particular topic.

I also note that we are about an hour and 35 minutes in, and the court reporter will need a break. So, what I'd recommend is we take a brief break at this point for the court reporter, who still has to type through my talking, and return at a quarter of. Then, maybe go for another half hour, 45 minutes, take a lunch break, and then come back. We'll try to wrap up with this panel before we take lunch, if at all possible.

So, let's take a break now, and return

at a quarter of. Thank you. Off the record.

(Recess taken at 11:37 a.m., and the hearing reconvened at 11:50 a.m.)

CHAIRMAN GOLDNER: Okay. We'll go back on the record.

First, we'll swear in the witness, Ms. Noonan, who is seated next to Mr. Dexter. And, then, once that's complete, we'll move back to Ms. Ralston and cross.

(Whereupon ***AMANDA O. NOONAN*** *was duly sworn by the Court Reporter, and added to the DOE witness panel.)*

CHAIRMAN GOLDNER: Please resume, Ms. Ralston.

MR. DEXTER: Mr. Chairman, should I ask Ms. Noonan a couple of introductory questions?

CHAIRMAN GOLDNER: Of course. That would be great. Thank you.

MR. DEXTER: Okay.

AMANDA O. NOONAN, SWORN

DIRECT EXAMINATION

BY MR. DEXTER:

Q Ms. Noonan, would you please state your name and position with the Department?

A (Noonan) Of course. My name is Amanda Noonan. I'm the Director of the Consumer Services Division at the Department of Energy.
Q And, Ms. Noonan, did you file written testimony on December 13th, 2023, in this docket?
A (Noonan) Yes, I did.
Q And did that testimony contain a description of your professional and educational experience as it relates to this docket?
A (Noonan) Yes, it did.

MR. DEXTER: Okay. Thank you. Ms. Noonan is available for questions.

CHAIRMAN GOLDNER: Okay. Please proceed, Ms. Ralston.

MS. RALSTON: Okay. And, Ms. Noonan, I am not sure if you were in the room. So, I'm going to just restate the question that I had started to ask.

CROSS-EXAMINATION *(resumed)*

BY MS. RALSTON:
Q And, so, I had referred the panel to the Motion to Dismiss, at Page 20, which is where the Department of Energy has a section of the Motion regarding the SAP implementation and resulting

Customer Complaints. Do you see that section? I think it's on Page 20.
A (Noonan) I don't have it open in front of me. But, please, go ahead.
Q Okay. The section is called "Liberty's SAP Implementation Resulted in Significant Customer Complaints to the Department", just for reference.
And, then, I also referred the panel to Page 1 of the Motion, where the Department of Energy argued that the case must be dismissed because "the 2022 financial information on which the filing is based cannot be reasonably relied on." Do you see that on Page 1 of the Motion?
A (Noonan) Yes.
Q And is it your position that the Company's financial information is the cause of the increase in customer contacts with the Department?
A (Noonan) I think there's a causal relationship between the two.
Q And, on Page 21 of the Motion, it states that, during "the 12 months following implementation of the SAP system, the DOE received 121 Billing and

Billing Adjustment contacts", versus "14" during the twelve months prior to implementation of the system. Do you see that?

A (Noonan) Yes. I do.

Q Okay. And are you aware that, in late 2022, there was a substantial increase in electric bills due to increased commodity pricing, with Liberty's rate increasing from 10 cents to 22 cents, beginning with service on August 1st of 2022, a rate increase that was reflected in bills issued starting in September of 2022, just prior to the SAP implementation?

A (Noonan) Yes, I am.

Q Okay. Can I now ask you to turn to Exhibit 8, at Bates Page 341, which is the Luth Research survey included with the Motion to Dismiss. And let me know when you have the exhibit?

A (Noonan) I'm sorry. What was the page number again?

Q Hang on one second. Bates Page 341. If you're in the Motion to Dismiss attachment, looks like it's 336. I don't know if that's helpful.

A (Noonan) Okay. Could you cite the number in the report itself, the page number in the report itself? I'm sorry. That's the document that I have open.

Q Give me one moment. I apologize, I think I got it turned around with the overlapping Bates numbers.

MR. DEXTER: So, if it helps, the Luth survey starts in Exhibit 8, on Bates Page 310.

MS. RALSTON: Thank you, Attorney Dexter.

BY MS. RALSTON:

Q And the page I was looking for is Page 12 of the survey itself. And, if you give me one moment, I can find the Bates page.

It is Bates Page 321 of Exhibit 8. And I apologize for the delay.

So, now that we are all there, do you see the bullet that states that cost is still the top complaint mentioned by dissatisfied customers?

A (Noonan) Yes, I do.

Q Okay. And would you agree that cost is not related to SAP implementation?

A (Noonan) That's correct.

Q Okay. And would you agree that there can be other customer issues that are not related to SAP? For example, a meter reading question or a billing issue that might be related to a customer's change in circumstance, like moving?

A (Noonan) All of those -- or, those two reasons that you just cited are certainly impacted by the billing system. Even though they may be outside of the billing system, such as a meter change or a move, but the billing system itself will impact the resolution or the appropriate handling of those issues.

Q So, it's your testimony that, if a customer moves, and, for example, didn't provide any notice to the Company, continued to get bills for a residence they no longer reside at, that that would be related to the SAP implementation?

A (Noonan) In that particular instance, no.

Q Okay. So, my question was, would you agree that there are other customer issues that are non-SAP related? So, would you agree that there can be customer issues not related to SAP?

A (Noonan) Sure. In the abstract, there could be, yes.

Q Okay. So, noting that there can be customer contacts that are unrelated to the SAP implementation, how did the DOE categorize whether an incoming complaint was related to SAP or not?

A (Noonan) The categorization of contacts to the Department's Consumer Division are not tied to a billing system used by a utility. They're tied to the reason for contact. However, review of these shows that the overwhelming majority, if not all of them, were related to some billing system issue.

Q So, if the Department isn't categorizing them based on their relationship to the billing system, how was that determination being made?

A (Noonan) By a manual review of all of the contacts.

Q And what criteria was that manual review using?

A (Noonan) The information that was provided by the customer, and the response provided by the Company.

Q So, was there a set of criteria or was it on a case-by-case basis?

A (Noonan) They were all manually reviewed individually.

Q   So, is that a case-by-case basis or were there a set of criteria being used by a Department staff?
A   (Noonan) It was a case-by-case review.
Q   Okay. And does the Department of Energy have a breakdown, by month, of the complaints related to SAP conversion, or SAP versus non-SAP complaints?
A   (Noonan) Again, that's not -- that's not a reason for contact within the Division's database. However, we do have a month-by-month count or can produce a month-by-month report of contacts on any given utility, and the reason why the customer reached out to the Department.
Q   Okay. And just to be clear, but it wouldn't be broken down by its relation to the SAP conversion?
A   (Noonan) Again, that's not a reason in the database for why we track contacts to the Department.
Q   Okay.
A   (Noonan) Customers don't specifically say that's why they're calling. They're calling about their bill, and an issue that's transpired as a result of something else.
Q   Would you agree that it is normal for a customer,

or typical, for customer contacts to increase after a system conversion?

A (Noonan) There are certainly always bumps that follow a system conversion. That is definitely the case. However, we found the number of issues that followed this particular conversion to be abnormal.

Q What level of customer complaints would the Department of Energy have expected?

A (Noonan) I don't have an expectation for a certain number. It's the severity of the issues, the quantity early on. There's no set expectation that "this number is good" and "that number is bad." It's just a comparative between past experience.

Q So, the determination here that the number of contacts was unusual is based on your experience?

A (Noonan) It's based on experience. It's based on looking back to see what transpired following other system conversions with other utilities.

Q Referring back to the Motion, at Page 21, the Department of Energy noted that, prior to its system conversion, Eversource had "70 Billing and Billing Adjustment contacts", and that this number doubled following its system conversion to "138". Do you see that?

A (Noonan) Yes.

Q Okay. And would you agree that the number of Billing and Billing Adjustments for Liberty was still lower than Eversource's, even with its increase following the conversion?

A (Noonan) I'm sorry, could you repeat that?

Q Sure. And maybe I should, before I ask you that question again, if you look up to the paragraph above that, it says that "the Department received 121 Billing and Billing Adjustment contacts" for Liberty. So, would you agree that Liberty had fewer Billing and Billing Adjustment contacts than Eversource after its conversion?

A (Noonan) Yes. The absolute numbers, that's the case. However, there's a significant disparity between the number of customers for the two utilities.

Q Did the Commission Staff, as the predecessor to the Department of Energy, recommend dismissal of Eversource's 2009 rate case as a result of that increase in customer contacts?

A (Noonan) No.

Q Okay. Would you expect that customer contacts will return to at or about baseline at the pre-conversion level, once the new system is stabilized?
A (Noonan) It's difficult to say what future trends might arise. But, typically, after a period of time, the complaint or contact levels will level off.
Q Okay. Are you aware that, in the first six months of 2023, so, from January into June, that Liberty reported 10.3 customer contacts per month related to billing and billing adjustments?
A (Noonan) I wouldn't have any idea what Liberty's records were regarding that.
Q Okay. So, are you -- are you aware then that, in the five months, from July to November 2023, Liberty reported only 6.8 customer contacts per month related to billing and billing adjustments, representing a 34 percent decrease from the first six months of 2023?
A (Noonan) Again, I have no access to Liberty's information.
Q Can I now refer you to Bates Page 266 of Exhibit 8, which provides a "Summary of Delayed

Invoices"? And you can just let me know when you're there.

MR. DEXTER: Attorney Ralston, could you provide the page reference again please?

MS. RALSTON: I said "266", but I think that may be incorrect. That may have been the old Bates number.

Yes. So, it is, for Exhibit 8, the correct Bates number is 240.

MR. DEXTER: We just need a minute to get there.

MS. RALSTON: Take your time. If you're referring to the attachment to the Motion, it's Attachment 5.

MR. DEXTER: Excuse me. The witness is right next to me, and I can't resist the urge to help her out, if that's okay with the Bench? I'm just trying to get her to the right --

CHAIRMAN GOLDNER: Yes.

MR. DEXTER: -- to the right page.

CHAIRMAN GOLDNER: Yes, please.

MR. DEXTER: Thank you. The witness is on the right page.

MS. RALSTON: Okay. Great.

MR. DEXTER: With no help from me.

MS. RALSTON: I will try to make this all worth our while.

BY MS. RALSTON:

Q So, do you see the chart on that page called "Summary of Delayed Invoices and Resolution by Date and Dollar"?

A (Noonan) Yes.

Q Okay. Would you agree that this summary table demonstrates that the Company had essentially caught up on the delayed billing by March of 2023?

A (Noonan) For the accounts that were identified for the Department in January of 2023, it does appear that the issues with those specific group of accounts had been primarily addressed by March of 2023.

However, there were additional accounts that continued to be problematic that were perhaps not identified in that initial number.

Q Thank you, Ms. Noonan. I now have just a few additional questions that I believe are for Mr. Dudley.

One follow-up question regarding the

revenue requirement update. This morning you stated, I believe, and you can correct me if I'm misstating, that "when a utility files its revenue requirement update, it always includes a technical statement." Was that your position this morning?

A (Dudley) That's been our experience, yes.

Q Okay. Are you aware that, in Docket DE 21-030, Unitil did not include a technical statement?

A (Dudley) I'd have to check on that. I don't recall.

Q Okay.

A (Nixon) May I add to that?

Q Sure.

A (Nixon) So, and I can't remember which case I looked, but I remember -- I recall that, once the update was filed, it was in response to a data request. So, sometimes it is filed that way as well. I cannot cite the case. So, there was explanation with the data response.

Q Okay. Would you also agree then, Ms. Nixon or Mr. Dudley, that, if the case were to proceed, and the Company was afforded the opportunity to provide rebuttal testimony, it could provide additional explanations as part of its rebuttal testimony?

A (Dudley) Certainly.

Q Thank you. Mr. Dudley, the Motion to Dismiss references -- one second, I'm sorry.

Mr. Dudley, in your testimony you filed in this proceeding, there's references to an "August 2016 Liberty Consulting Group Report", is that accurate?

A (Dudley) Yes, it is.

Q Okay. And did that Consulting report include any recommendations related to the Company's financial accounting?

A (Dudley) It did. It did cover -- the management audit was quite broad, and it did cover the area of accounting.

Q Are you aware that the Liberty Consulting Group prepared a supplemental report in November of 2017?

A (Dudley) Yes, I am.

Q Okay. And did you review that supplemental report?

A (Dudley) Yes, I did.

Q And do you recall if that supplemental report described the progress made by the Company in implementing the recommendations from the 2016 report?

A (Dudley) I recall that it noted improvements in the area of customer service. However, we found Liberty's -- that the Consulting's findings, in terms of capital investment, to be inclusive.

Q And would you agree that the information in that supplemental report could be helpful to the Commission, if it were to consider the 2016 report?

A (Dudley) It would be helpful. I'm not sure how helpful it would be to Liberty. And the reason why I say that is, because, as part of their updated review, Liberty Consulting reviewed four additional projects. To be specific, those projects were the Concord Training Center, the CNG Compressor Project, the Keene Conversion Project, and the IT Expenditures Blanket Project. And what they found was a continuation of the deficiencies that they had reported in the original Audit Report.

Now, they did -- they did correct themselves in the update on that, because the --

it was a matter of timing. And, by that, I mean that the four projects that they had reviewed were 2016 projects, they had been initiated. Some of them completed prior to Liberty Consulting issuing their findings and their recommendations.

However, as a follow-up, they did look at the Keene LNG Project, which was a 2017 project. And they came to the conclusion that similar deficiencies were continuing. But Liberty did find that a few of the recommendations had been adopted by Liberty Utilities. One of those being the percentage variances in budgeting. Liberty had adopted Liberty Consulting's recommendation of a range of 5 to 10 percent. That was included in Liberty's policy and procedures. Liberty also adopted the monthly committee meetings to discuss the variances.

And, excuse me, the third one adopted was the adoption of the project close-out report, and that was made a part of Liberty -- again, Liberty's policies and procedures.

Q Thank you. And, then, just a couple final questions. Again, I believe these are for you, Mr. Dudley.

Earlier, Attorney Dexter had asked the panel's opinion on the Company's proposal for the 90-day stay and the third party review. Do you recall those questions?

A (Dudley) I do, yes.

Q Okay. And one of your statements was that "the Company wanted to use an auditor that it has an existing relationship." Do you remember stating that?

A (Dudley) That's my understanding from the January 4th hearing, yes.

Q And do you recall, from the January 4th hearing, when I explained that the reason for that was timing?

A (Dudley) Vaguely, yes.

Q Okay. And do you also recall the Company offering to let the Department of Energy weigh in on selection of the auditor or -- and/or the process for performing that third party review?

A (Dudley) Yes, I do.

MS. RALSTON: Okay. That's all the Company has. Thank you.

CHAIRMAN GOLDNER: Thank you. We'll turn now to Commissioner questions, beginning with Commissioner Simpson.

I'll just check first, to see if the OCA or Dartmouth College has any questions for Ms. Noonan?

MR. KREIS: We have no questions for Ms. Noonan.

MR. GETZ: No questions, Mr. Chairman.

CHAIRMAN GOLDNER: Okay. Thank you. We'll turn to Commissioner Simpson then.

CMSR. SIMPSON: Thank you. And I'll first turn to Attorney Ralston.

I'm struggling to find the FERC Form that was filed in exhibits. If the Company could identify the exhibit, and, if it's not in an exhibit, in the record, and the corresponding page number, that would be helpful.

I'll ask these witnesses some questions, but I'm looking for that reference. I can't find it.

MS. RALSTON: You're looking for the FERC Form 1?

CMSR. SIMPSON: Yes.

MS. RALSTON: Okay.

CMSR. SIMPSON: That's filed as an annual report. But I'm looking for it herein. Thank you.

MS. RALSTON: Okay. Thank you.

CMSR. SIMPSON: And please, when you find it, let me know.

MS. RALSTON: I will. Thank you.

BY CMSR. SIMPSON:

Q So, I'm just first wondering, particularly for Ms. Moran, the audit process that you went through was clearly very thorough. Did you feel that the Company was transparent and confident in their responses and engagement with the Audit team throughout that process?

A (Moran) Partially yes and partially no. But, like the time it took to have some of our audit requests answered, caused significant delays. I mean, we had one question that was outstanding for 77 days. And, by the time we get that kind of response, the reason we even asked might have passed through our brain already.

Q Uh-huh.

A (Moran) The process could have been much faster, and more direct, had we had access, as we have in prior audits in prior years, to the people who actually do the work. I understand that our questions go through the regulatory review as if their data requests. And I understand that, for tracking purposes. But it made it much more difficult to have a back-and-forth.

Q Did you feel that, when questions were raised and responses were provided, that there was confidence in the response provided to the Department?

A (Moran) If we had follow-up questions, we always asked, and they provided answers to us.

Q Okay. And I believe I understand your testimony to be, with respect to the time, Attorney Ralston asked you a question about "did the Department seek more time in asking questions and seeking responses?" And you testified "no" to that question, correct?

A (Moran) That's correct. When we finally get to the stage where we issue a draft report, as I stated earlier, we started the audit in May. So, we took five months before we finally issued a draft report.

In the interim, there were lots of other audits taking place. And we finally have to stop and say "This audit's done." We're doing other audits, that I won't get into. But, yes, sooner or later, we have to just say "No, we're done."

Q And, of course, --

A (Moran) And that's really where we came to.

Q Of course, there's a procedural schedule in place, with hearing dates set --

A (Moran) Right.

Q -- for this proceeding.

A (Moran) Correct.

Q And you have to work through the audit process in line with that procedural schedule, if I understand correctly?

A (Moran) Typically, the audit is not part of a procedural schedule. In a perfect world, the audit work and the final report would be done before the first set of data requests are issued. That didn't happen here, just because of timing. Timing is a reason for a lot of things that happen.

But we really try to get the Audit

Report to the Regulatory Staff, so they can look it over. If there are things they want to look into further, they can use the Audit Report as the basis for some of their data requests.

A (Dudley) Commissioner Simpson, if I may interject?

Q Please.

A (Dudley) And I agree with Ms. Moran. That the Audit Report is considered a key piece of information for Department Staff, and also for our cost of service consultant. She also relies on those findings to issue her final conclusions about the revenue requirement.

CMSR. SIMPSON: Okay. Thank you. Attorney Ralston?

MS. RALSTON: So, it's my understanding that the FERC Form 1 is filed routinely with the Commission. And that is the version we have been relying on.

If you would like it submitted separately as a formal exhibit, we would be happy to do that. And I would also make that offer, because I think, on the last hearing day, you noted there were "some presentation issues".

CMSR. SIMPSON: Yes.

MS. RALSTON: And it's my understanding that is a function of the software used to upload the form to FERC. But there is a way that we could get you a "clean" copy. So, we would be happy to do that, if that would assist you. Or, we could even send it during the lunch break, or, you know, see what happens, for this afternoon, if that would be helpful?

CMSR. SIMPSON: Do you know if the Department was provided with a "clean" copy of the form?

MS. RALSTON: I believe that they're -- they have access to the version that's available online. We were not aware that anyone was having trouble reviewing it. So, I would have to defer to them, if they're having trouble with the same presentation issues.

CMSR. SIMPSON: Okay. Because I still just see the one that's filed on the Department's website as an annual -- electric annual report. And I wanted to ask these witnesses, how did they even comprehend the data that's afforded in this form? Because, when I look at it, I just can't tell what is accurate and what isn't, given the presentation problem.

MS. RALSTON: Yes. And I don't know, I mean, the Department of Energy could explain, I don't if maybe they need to respond, --

CMSR. SIMPSON: Okay.

MS. RALSTON: -- if they have the software, I'm not sure. But we would be happy to provide one that eliminates that presentation issue.

CMSR. SIMPSON: Okay. Thank you for that. So, I'll ask these witnesses.

BY CMSR. SIMPSON:

Q You did review the FERC Form 1 that the Company filed for 2022, correct?

A (Dudley) Yes.

A (Nixon) Yes.

Q Did you see the same presentation issues that I've noted multiple times now?

A (Nixon) Yes.

Q I'm looking at the form page -- or, pdf Pages 45, 46, 47, 48.

A (Moran) If I may?

Q Please.

A (Moran) Our auditor asked for a legible copy, and we do have one.

Q You do. Okay. So, you were able to, at least from the Company's data, get a version of this form that was --

A (Moran) Legible.

Q Legible. Okay.

A (Moran) And Attorney Ralston is correct. This is a FERC issue, not a Company issue, not a Department of Energy issue.

Q Excellent. Thank you for that.

A (Nixon) But, if I can speak for myself, that the version we have is the same version you have.

A (Dudley) Yes.

A (Nixon) Audit was the only one that had a separate one.

CMSR. SIMPSON: Okay. If the Company could file that, that would be appreciated?

MS. RALSTON: Yes. We will get that today.

CMSR. SIMPSON: Thank you.

MS. RALSTON: And I apologize. And, in the future, we would just ask that, you know, if someone had let us know, we would have gotten this in much earlier. So, I do apologize for that issue.

CHAIRMAN GOLDNER: We'll just make that "Exhibit 9".

*(**Exhibit 9** reserved)*

BY CMSR. SIMPSON:

Q At the beginning of direct, Ms. Moran, you were asked some questions about a "payroll report", do you recall that?

A (Moran) I do.

Q My understanding thus far is that the information provided by the Company, prior to October of 2022, isn't of concern. That the data that was originally in the Company's Great Plains system, you had confidence in. And it was the data that then was provided for October '22 through December '22 that migrated from the SAP system is where you have a concern. But, please elaborate.

A (Moran) Well, I'm not sure that's completely correct. Because what we looked at was the year-end payroll register, so that, of course, would include the entire test year. And we were unable to verify the payroll system to the general ledger.

So, there wasn't a month-by-month review of the payroll register to Great Plains, and then to SAP. It was a year-end review, and we couldn't accomplish that.

Q Was Great Plains used for both the general ledger and the payroll system historically?

A (Moran) I, frankly, am not aware of what system the payroll was. But I don't think it was the same.

Q And, to your knowledge, is payroll and the general ledger now managed by the Company in the SAP environment?

A (Moran) I'm unsure.

Q Okay. So, you neither have confidence in the data that was provided from Great Plains nor SAP?

A (Moran) I'm not sure I'd phrase it that way. Because, as I said, we looked at the year-end payroll register. So, assuming the Great Plains activity for the year moved to the correct SAP account, understanding the mapping issues, there could be an issue, there could not be, I mean, it could be fine.

Q Uh-huh.

A (Moran) But we were unable to determine if any of

the payroll accounts within the SAP system that would show to which expense account or which capital accounts any of the payroll dollars hit.
Q Okay. Thank you.
A (Moran) Sure.
Q And this is for the entire panel. Is it the Department's position or understanding that there's a forthcoming revenue requirement update that the Company will be providing for this case?
A (Dudley) That was our understanding from counsel from the January 4th hearing, yes.
Q But you have not yet received an update to the revenue requirement?
A (Dudley) Well, I assume that we will receive it, depending on whether or not the rate case continues.

CMSR. SIMPSON: Does the Department have any position as to whether or not FERC or securities regulators should be contacted, given the concerns that arise from the information that's been provided?

And I'm happy to direct that at Attorney Dexter.

MR. DEXTER: Well, I guess I'd give the

same answer I gave on January 4th, which was that we haven't looked into that.

CMSR. SIMPSON: Okay.

MR. DEXTER: And, again, we've been focused on the rate case, and the impacts of the information on the rate case. And don't have a position on, you know, what might need to be done at the FERC, that hasn't been our focus.

CMSR. SIMPSON: Okay. Thank you.

BY CMSR. SIMPSON:

Q   So, then, my last question for the Department witness panel, as a general matter, do you have concerns about the financial health of this utility?

A   (Dudley) We don't know. We are deeply concerned about the mapping issues. We are deeply concerned by the fact that Audit was unable to verify the accuracy of some of the corrections that were made.

And whether or not that impacts the financial stability of Liberty? I think it's really a matter of correctly processing accounting information. In other words, I think the revenue dollars are there. Certainly, we're aware that SAP -- one of the functions of SAP is a cash management component. We don't know how that's working. We're only aware of the impacts regarding the general ledger and the accounting. But our assumption is that it's probably working okay.

But I really don't -- I don't have any information at my fingertips, Commissioner Simpson, to give you a specific answer.

Again, we are concerned about the way the information is reported and the accuracy of that information. But, whether or not it has a detrimental impact on Liberty as a going concern, we really don't know.

CMSR. SIMPSON: Okay. Thank you. That's all I have, Mr. Chairman.

CHAIRMAN GOLDNER: Okay. We'll move to Commissioner Chattopadhyay.

CMSR. CHATTOPADHYAY: Good afternoon.

BY CMSR. CHATTOPADHYAY:

Q I think you probably recall that there was, on the 4th, during the hearing, there was some discussion about -- I think it was Attorney Dexter who had said, you know, "the facts were laid out in the Motion, and no one has disputed them." And, then, the Company essentially said that, I'm going to go there, actually, in the transcript right now, that they -- they "understood that the adjustments were necessary", and their position was that -- that "the 2022 books is not the starting point", those adjustments, you know, like I said, "were necessary", like they were made. And it was stated that "they were made, they were explained, they were supported."

So, I want to get a sense of whether DOE agrees that the adjustments that the Company is talking about, you agree that they were explained and they were supported?

A (Moran) I'll start, just from the Audit perspective. When the Company says they "did the adjustments", I think it's more along the lines that they adjusted the Rate Filing. They didn't adjust their SAP account structure, they didn't adjust the FERC, because they essentially used numbers that they thought should be there, not the numbers that were there.

So, from Audit's perspective, it's not

really a relevant statement, because the test year 2022 figures were what they were.

Jay?

Q You know, anything others may want to add?

A (Nixon) Go ahead. Yes. Go ahead.

A (Dudley) Yes. Well, I agree with Ms. Moran. Whether -- the problem is accuracy, and whether or not they're accurate; we don't know.

In terms of the test year, yes, adjustments were made in the 2022 test year to that. And our understanding, again, is that more adjustments are coming.

In terms of adjusting the SAP mapping errors, those largely occurred in 2023. In 2022, the books were closed. They can't be changed. There's no going back to fix them. They're closed.

But, now, we're -- again, we've been made aware, in the last hearing, on January 4th, that Liberty is discovering additional mapping issues. And that, as I explained to Mr. Dexter earlier this morning, there will likely be additional corrections made in 2024.

So, all of those things combined,

Commissioner Chattopadhyay, make us very uneasy, in terms of reliability of the test year numbers, and whether or not 2022 is still a viable test year.

A (Nixon) And I'd like to add to that. I'd like to add to that that, and I don't have it in front of me, but I believe there's an attestation that the Company needs to make, and, as part of that, they have to verify that they've indicated any differences in the filing, and that was not made. But the attestation was made, but that that difference was not made, is what I'm understanding.

Again, I can't pull up the reg right in front of me quickly, but there is a requirement to do that.

Q On January 4th, there was, like you mentioned, the Company made us aware of additional SAP issues. And, as I understood it, it was probably noted or those issues were noted before the end of the last year.

But has there been any back-and-forth for you to know a little bit more and then -- and come to some conclusion about there might be

other changes that's happening in 2024 for being noted, you know, as issues with the SAP? Are you aware of it or have you had -- did you continue the conversation with the Company about that?
A (Dudley) No. There were no conversations with the Company, because the period for discovery had expired.
Q Okay. So, this is a question for -- really related to the audit, so, I'm going to ask this to Ms. Karen Moran. So, I'm going to quickly, this is -- it's a general question.
When there's a rate case filing, and I'm not an auditor, I just -- I might use terms that are not exactly the way you use them, but -- so, there's an annual report, and then there's a rate case filing. You're trying to reconcile them as much as possible, right?
A (Moran) Correct.
Q And, in prior rate cases that you've worked on such, in other words, for so many years, like usually there are issues?
A (Moran) Sure. What we find are things like one account is reflected on the report in the wrong spot. They tell us why. It's usually a

difference between GAAP and FERC. We kind of agree or disagree on that. But it's a one-for-one. It's not the extent of the -- it's not a problem that the dollars within the account that's in the wrong spot can't be verified. You know, we trace those amounts. We say "Yeah, that account is right. It should be on the liability side of the balance sheet, not the asset side." Those are the kinds of issues we typically see.

What we saw in this case is distinctly different.

Q So, as I understand, and correct me if I get it wrong, the kind of issues that you usually discover, when you're comparing, it's more about, you know, you may still have disagreements, but it's really about where things should go to, in terms of account line numbers and things like that?

A (Moran) Yes. And they're very minimal.

Q Okay.

A (Moran) You know, there might be one or two accounts that we argue about.

Q So, in your experience, this instance, like in this rate case, that problem is perhaps there,

but it's also significant, number one?
A (Moran) That's correct.
Q And, number two, given what's going on, you're not sure there might not be others that are out there. Is that a correct understanding?
A (Moran) That's correct. Because we looked at what we were able to verify, clearly, we didn't find all of the mismapping issues. Because, as Mr. Dudley has already said, things are turning up a year later, as we learned at the hearing a couple weeks ago.
Q To keep it short, I'm just going to go to the -- this is Exhibit 8, and again about audit. I'm going to pick maybe a couple of examples.
So, look at what you had for Audit Issue Number 2, I think it's Bates Page 152. And the Bates Page on the right extreme is 178. So, just to be -- I think we're using 152. Let me know when you're there.
A (Moran) I'm there.
Q Okay. So, the "Audit Comment" at the end says: "Audit concurs and requests that copies of any adjusting journal entries be provided to Audit within 30 days of this Final report." Did you

receive anything?

A (Moran) No.

Q Does the DOE otherwise, not the Audit Division, have anything to add? Like, when something like this is flagged, do you follow up, and what happens, if at all?

A (Nixon) We did not follow up and did not receive anything.

Q Okay. So, let's go to Bates Page 1 -- I'm going to go there. So, let's go to Bates Page 169. A very similar question at the end, it says "Audit concurs with the Company adjusting the filing."

So, these -- are these adjustments being followed through? Or, are you essentially saying "all of these will be done next time around"?

So, I'm trying to understand whether any of the improvements that you're talking about get reflected in the rate case?

A (Moran) They should be reflected in the updated revenue requirement schedules. Audit doesn't review the updated filings, because the audit takes place against the original filing. That's why this is a tool that we give to the Regulatory

Staff. So, they see all of these issues that say "the revenue requirement will be updated". And, as Ms. Nixon said earlier, it's hard for them to know if these adjustments, if any, resulting from data responses, if any are identified by the Company, if they have all been included in the updated revenue requirement schedules.

Q Okay. So, that's why I'm going to go to DOE and ask whether, for example, this one, which is Audit Issue Number 11, would you know that whether that was reflected properly in recalculating the revenue requirement?

A (Nixon) So, as I noted earlier, we were not able to go back and verify. I mean, as I sat here, as you were speaking, I went to the filings update and saw that they listed it, and said it was superseded by something else. But, literally, just did that on the stand. We did not check and verify that they have made every update that they said they were going to update.

Q Can the DOE do that? I mean, doesn't have to do it right away, but can that be a --

A (Nixon) Well, I guess our concern is that it seems that the errors and updates are ongoing. I mean, we just heard on January 4th there were more updates. So, we don't even have the latest update filing.

And I hesitate to offer that we can do that, because that is an -- it seems like a big undertaking at this point.

Q So, let me put it differently. I think I understand the point about, when you have so many mistakes, then you start worrying about "there might be more", and, so, all of that is clouding your approach to concluding that this is all taken care of. Okay. So, that I fully understand.

What I'm asking is, there are these 28 audit issues, okay? And, to the extent you know whether they have been accounted for, the ones that the Audit concurs in, then said "this is the adjustment that the Company has agreed to do", that's what I'm trying to check.

And it's not about -- I'm not saying that, having made you go through that, you know, I'm therefore sort of also asking you what your opinion is about whether there may not be other issues, okay. So, I'm just --

A (Nixon) So, let me just repeat what I think I heard you were asking. Were you saying "Can the Department or has the Department double-checked all of the issues that were addressed in the audit and the data responses, and fix them?"
Q The ones where the Audit concurs?
A (Nixon) The Audit -- we have not done that.
Q Yes. And I'm saying, is it possible to do that?
A (Nixon) I guess I'd -- I'd have to -- to the extent it's in the filing, that is something -- that's something that our Department could do.
Q Yes.
A (Nixon) If it's in the books and records, that's something that we don't dive into.
Q No, I'm talking about in the filing?
A (Nixon) That's something that, yes, it is something theoretically it could do. But, as I mentioned, I'm worried that those aren't all the errors and corrections.
Q That I understand. So, you can -- you know, that's your position. But the ones that are listed that it says "Audit concurs with the Company adjusting the filing", can you go back and check?

A   (Nixon) And I -- I think I would have to look at every one of them and see what it says.
Q   Yes.
A   (Nixon) But I believe that's something we could do.
Q   Yes.
A   (Nixon) But I just want to note, there were a lot of statements like that made in the data responses as well. And, I mean, those were numerous. So, I --
Q   Yes, I would -- I think what I'm asking is, based on the audit issues, there are 28 of them, there are some that the audit comment at the end is "Audit concurs with the Company adjusting the filing."
A   (Dudley) Commissioner, it's one thing to do a line-by-line verification to see whether or not these categories were included. I mean, sure, you can do that. Our problem is verification, for accuracy.
Q   Agreed. I understand that.
A   (Dudley) Yes.
Q   I mean, I'm not discounting it. I'm just --
A   (Dudley) Okay.

CMSR. CHATTOPADHYAY: I think that's all I have for now.

CHAIRMAN GOLDNER: Okay. Just a quick check with Attorney Dexter, before I just have a few questions. Would you prefer, Attorney Dexter, to do redirect after a break or dive into it after my questions, which won't be more than five minutes?

MR. DEXTER: I don't have a lot on redirect. I think we could do it before the lunch break.

CHAIRMAN GOLDNER: Okay. Let's do that then.

So, just a couple of questions.

BY CHAIRMAN GOLDNER:

Q Ms. Moran, your audit was a sample audit, right? You didn't go through every single line of the Company's books and records?

A (Moran) Correct.

Q Yes. And, when you looked at issues, you identified, I think, 28 Audit Issues, and that was -- this question was kind of asked earlier, but I wanted to come back to it, that was kind of out of how many? Did you look in 28 areas and find 28 issues? Or, did you look in a few hundred areas and find 28 issues?

A (Moran) So, what we do, the entire Audit Staff, there are five of us, we all have different areas of, basically, the FERC Form 1 that we look at. So, the balance sheet accounts, plant additions, retirements, adjustments, revenues, income statement, debt. Those are the kinds of areas we look at.

So, it's not that we all decide "I found ten issues in this one section, should we include one?" That's not how it works. We go through, and we certainly see some areas that have no issues. They tie to the books, the supporting documentation is fine, that results in no audit issue.

So, you can't -- you can't really look at it in that context.

Q I'm just trying to understand. You mentioned before that the issues were "significant". So, we had some large dollar issues, I understand that piece of it.

I'm just trying to understand what I might call a "DPPM" level, an error level. Is it, normally, you would look through the books and records, and you -- and you said, I think, before that you "normally find about the same number of issues". The concern here is that the dollar figures were much higher with the audit issues?

A (Moran) It's not so much the dollar issues, although there are significant ones. The first one on your request from the Bench, half a billion dollars, that's a significant dollar amount. But it's the mapping issue. It's the fact that we found expense accounts in balance sheet accounts, or balance sheet accounts mapped to expense accounts. And we've just never come across that kind of mismapping problem.

And Audit Issue Number 1 lays out a bunch of the problems, clearly not all of them. And that's much more troubling to me as an auditor, than, at the end of the day, it netted out to, you know, $500,000. It's critical that the mapping be fixed.

Q Thank you. Second question is, so, this filing from the Company was based on the books and records from 2022, the test year. If the Company were to refile with a 2023 test year, or 2024 test year, what's your confidence that those books and records would be I'll call it "good enough" to proceed with a rate case?

A (Dudley) Given the amount of corrections that were made in 2023, we wouldn't consider 2023 reliable. We're basically in the same place, Mr. Chairman.

A (Nixon) And I just want to add, I mean, given that, at the last hearing, additional errors were found, seems like there's going to still continue to be corrections into 2024. And to the extent, at this point, we still have not gotten verification that all the issues have been corrected. So, we're -- we can't even -- we don't know if they're corrected even to this day.

Q Okay. Thank you. Just one last two-part question. And I believe you've already answered this, but I just want to close the questioning for the Department with a clarification.

And that is, does the Department believe that it can proceed in the rate case with the books and records as they are?

A (Dudley) No, we cannot.

Q And Part B of the question is, if the Company's -- if the Commission were to approve the Company's proposal for this three-month delay, with an auditor coming in and reviewing the records, and ostensibly fixing the issues, can you maybe summarize the Department's position again on that proposal?

A (Dudley) Well, the Department does not support the proposal, as far as we know, from the Company. We don't think the auditor should be chosen by the Company, much less have a business relationship with the Company. That's not an independent third-party audit, in our estimation. That's more kind of the "fox guarding the chicken coop".

So, the other part -- the other piece of that is, Liberty hasn't really specified the qualifications of the auditor. We believe that the auditor should have an expert level of understanding of the SAP system and how it works, and how the mapping works. That should be a requirement. The auditor should also be -- have an expert level of knowledge regarding FERC accounting and the FERC Chart of Accounts, and how that works, and how the reporting works. We also think that, incorporated into any type of audit, there should be, as Ms. Moran mentioned earlier, an IT audit, as to how the SAP system is actually functioning, and how the conversion process was carried out.

But, even then, Mr. Chairman, would we have any level of comfort? Well, we don't know. Because would these -- would these auditors actually capture all of the errors that exist out there? We still don't know the extent of the errors or how prolific they are.

But the problem is that this audit would have to be very comprehensive and very exacting, which means that they would have to actually get down on the transaction level, and review most of the transactions. That's a very daunting task. Meaning, that an audit like that wouldn't be accomplished in 90 days. It would probably be accomplished in 120 days or more.

So, and the other -- the other outcome to consider, Mr. Chairman, is that, after all is said and done, after all that work is completed, the auditor may issue an adverse opinion, and simply state "We can't figure this out either. We can't tie back all the numbers." In which case, they would issue an adverse opinion. And, so, we're back to square one, after spending all that time and money.

Q Okay. I'll just --

A (Nixon) And if -- and may I just add on?

Q Please.

A (Nixon) Just, I mean, the fact to have -- give the time delay for this auditor, then we would need additional time as well on top of that. And the clock's ticking, and statutory requirements, and contractual arrangements. I mean, there's just -- it all snowballs as to what -- what that triggers.

A (Dudley) Yes. If I could just add to Ms. Nixon's comments?

If the Commission determines that Liberty should not choose the auditor, well, then it would either be the Commission choosing the auditor, which is what the Commission did in the last management audit with Liberty Consulting, the PUC commissioned that particular auditor, or it would be the Department. But, in either case, we follow the same process. We issue an RFP, we go through that process. We do a review process of the RFPs. And, then, we send a candidate proposal to Governor & Council. That's a very long process. You're talking six or seven months, probably. So, we may not, if that's the case, then nothing may be resolved until the end of 2024 or into 2025.

So, it's a very daunting process. If, you know, if the Department were to agree to any audit process, it would have to contain all of the elements that I mentioned earlier.

Q So, I think, and this is just my follow-up, I think what the Department is suggesting is that the next opportunity for the Company is to use a 2024 test year, to use 2024 to get the books and records clean, so that, in early 2025, the Company could make a rate case filing that the Department could be comfortable with?

A (Dudley) I could say that that's a possibility, but I can't say that with any certainty. Because, again, we still don't know the extent of the errors, and whether or not those errors are going to continue into 2024.

Q Yes. I guess I'm just asking for the Department's position or opinion on the process that it would recommend to the Company, as opposed to -- I understand that there's no certainty in the -- in any proposal. But I think what I heard you say is a 2023 test year is not an option, from the Department's point of view. Therefore, using 2024, to clean everything up, would be the best option, so the Company could have a rate case filing as soon as it could?

A (Dudley) Yes. That would be a possibility, Mr. Chairman. And our position all along has been that Liberty should simply withdraw this rate case and start over.

Q And, sadly, I have one more follow-up. And that's the -- I believe the Department's position would be that the rate case expenses should be withdrawn, and that the temporary rates that were approved should be returned to ratepayers?

A (Dudley) If the Motion is approved, yes.

Q Okay. Which is --

A (Nixon) Can I clarify? By saying "withdrawn", meaning that the ratepayers aren't paying the consultant expenses, is what you meant by that statement?

Q Yes. If the Commission grants the Motion to Dismiss, I believe the Department's position is that there should be no rate case expenses the ratepayers are paying for with respect to the current filing?

A (Nixon) Well, yes. Ratepayers should not pay. There are still rate case expenses that our consultants and other consultants need to be paid. So, our position is shareholders should pay for that.

Q Yes, I understand.

A (Nixon) Okay. Okay.

Q And, then --

A (Nixon) Just wanted to clarify.

Q Thank you. And, then, with respect to temporary rates that were granted, and I might be misremembering the number, perhaps Attorney Dexter could correct me, I think it was something like $5 million.

MR. DEXTER: That's correct.

BY CHAIRMAN GOLDNER:

Q That's correct. Do you -- the Department's position on that would also be that that needs to be reversed out. And that, to the extent that any money has been collected so far, that that would need to be returned to ratepayers. Is that the Department's position?

A (Dudley) Yes. If the Motion to Dismiss is approved, the rate case comes to an end.

Q Right. Right. And then that money -- I just want to verify, your position is, any money collected would need to be returned to ratepayers, correct?

A (Nixon) Yes.

A (Dudley) Yes, it would, because it would be as if the rate case was never filed.

CHAIRMAN GOLDNER: Right. Right. I just wanted to validate that before you were --

WITNESS DUDLEY: Correct.

CHAIRMAN GOLDNER: -- off the stand. Okay. Thank you.

Do my fellow Commissioners have any follow-up questions, before we turn to redirect?

CMSR. CHATTOPADHYAY: No.

CHAIRMAN GOLDNER: Okay. Thank you. Attorney Dexter.

MR. DEXTER: Thank you.

REDIRECT EXAMINATION

BY MR. DEXTER:

Q So, Ms. Moran, earlier today you made a statement, and I'm going to try to paraphrase it. It had to do with what your understanding was of Liberty's external auditors, and why they were of the opinion that the 2022 books should not be reopened and corrected for these mapping issues. Do you remember answering questions about that?

A (Moran) I do.

Q Can you -- can you just explain what it is that your understanding was the position of the external auditor, and how you got that information?

A (Moran) Well, there was certain communication with the auditees, I can't remember who specifically, but --

Q I'm sorry, communication with who?

A (Moran) With the auditees.

Q With Liberty or --

A (Moran) Liberty.

Q Liberty, okay.

A (Moran) I can't remember who specifically. But, when I asked if the external auditors were aware that the FERC Form 1 was wrong, basically, it didn't tie to the books of the Company, they said "Well, the natural accounts roll up to the Corporate level, and that's what they were focused on."

So, they weren't going to reopen the Corporate books to fix at the regulatory level the filing that the Company made with the FERC Form 1.

Q Okay. And just to be clear, that's not your opinion, that's information you heard from Liberty, during the course of the audit?

A (Moran) Correct.

Q Okay. You also got some questions about time, and how long an audit takes. And I think you said just recently that, you know, "at some point, it has to come to an end." Did the amount of time that you and your time spent on the mapping issue detract from an analysis that you would typically do in an audit concerning the underlying costs that a company incurs?

A (Moran) It did take much longer to verify that accounts reflected on the FERC Form 1 and in the filing itself did not agree with the SAP year-end account numbers. That's correct.

Q But my understanding is, as part of a typical audit, you would go beyond just this checking of the reports versus the rate case expense, you would actually analyze the underlying costs that are contained in the accounts, once they ended up in the right place, right? Is that true?

A (Moran) That's true. And we were able to do some of that. You know, we didn't spend five months just trying to verify SAP to the FERC to the Rate Filing. We were able to get into some of the detailed analysis that we typically do, but not to the extent that we would have had they all matched.

Q Thank you. And the panel was asked a question about whether or not the Department is concerned about the financial stability of Liberty. And, Mr. Dudley, you answered the questions.

Is it your understanding that all utilities, including Liberty, file forms that are called "F-1", not to be confused with the "FERC Form 1", but they're filed with the New Hampshire PUC and the Department of Energy, they're called an "F-1" form, and those report on a company's overall operations and earnings, and the calculation is in the form of a return on rate base calculation?

A (Dudley) Yes. Those are quarterly reports, Mr. Dexter.

Q Okay. And, so, if the Commission or the Department of Energy wanted to monitor the financial stability, they could look, there's a report every quarter, and each quarter is looking back twelve months, correct?

A (Dudley) Yes. Correct.

Q Okay. And those, at least I find them in the e-filing, those are electronically filed, is that correct?

A (Dudley) Yes.

MR. DEXTER: Okay. That's all the questions I have.

CHAIRMAN GOLDNER: Okay. Thank you. The Department of Energy witnesses are now excused. Thank you for your time today.

We'll now take a break for lunch, returning at 1:45.

(Lunch recess taken at 1:02 p.m., and the hearing reconvened at 1:48 p.m.)

CHAIRMAN GOLDNER: Okay. We'll go back on the record.

I see that the Liberty witness panel is on the stand. But without the witness that you were hoping for?

MS. RALSTON: Yes. I was just going to confirm. Ms. Preston will not be able to join us today. I spoke with counsel and just let them know ahead of time. And, of course, if there were specific questions that these witnesses can't answer, we'd be happy to take a record request. And we do apologize.

CHAIRMAN GOLDNER: Okay. Well, I hope everything is okay with the witness and her family.

Okay. Let's move forward. And, Mr. Patnaude, if you could please swear in the witnesses.

*(Whereupon **LUISA READ**, **PETER DAWES**, and **ERIN O'BRIEN** were duly sworn by the Court Reporter.)*

CHAIRMAN GOLDNER: Okay. Thank you. And we'll start with the Company, and direct.

MS. RALSTON: And one more procedural

issue before we proceed. I just wanted to confirm the Commission received the FERC Form 1 during the lunch break?

CHAIRMAN GOLDNER: Thank you. We received Exhibit 9, and we'll put it in the docketbook. So, thank you for being so prompt with the filing.

MS. RALSTON: Yes.

LUISA READ, SWORN

PETER DAWES, SWORN

ERIN O'BRIEN, SWORN

DIRECT EXAMINATION

BY MS. RALSTON:

Q Okay. So, I'll begin with you, Ms. Read. If you could please state your name, position, and responsibilities?

A (Read) Good afternoon. My name is Luisa Read. I am the Vice President of Transformation, Enterprise System, and Process Strategy at Liberty. I have a CPA Finance designation in Canada, Ontario. I also have a Finance degree from the University, in Toronto. I have been working with Liberty for 25 years, in the Finance Department in our Corporate Head Office, in

Oakville.

I have -- four years ago, I accepted a role on the Customer First Transformation Program to be the finance lead for our Customer First Program, primarily involved in all of the finance processes that is included in the Customer First Program, including the design of our new Chart of Accounts, our general ledger, accounts payable, fixed assets, time entry, and financial reporting.

Q Thank you. And are you generally familiar with the Department of Energy's Motion to Dismiss and the Company's Objection to that Motion?

A (Read) Yes.

Q And are you also generally familiar with the Company's rate case that is the subject of this docket?

A (Read) Yes.

Q Okay. Mr. Dawes, would you please state your full name, position, and responsibilities?

A (Dawes) Yes. My name is Peter Dawes. I'm the -- whoops, sorry, it's not on. Apologize for that.

My name is Peter Dawes. I'm the VP - Finance and Administration for the East Region of

Liberty Utilities. So, that would include New Hampshire, as well as various other states, and the Province of New Brunswick. I'm responsible for the financial accounting and reporting for the East Region of Liberty Utilities, including the New Hampshire utilities.

I've been with the Company for about, I would say, six and a half years. But I've been with utilities for the last 30 years in finance and accounting roles.

Q And are you also familiar with the Department of Energy's Motion to Dismiss and the Company's Objection to that Motion?

A (Dawes) Yes, I am.

Q And are you also generally familiar with the Company's rate case filing?

A (Dawes) Yes.

Q And you did not sponsor any testimony in support of that Initial Filing, is that correct?

A (Dawes) I did not.

Q Okay. But was your -- were you or your team involved in the transition of the SAP accounting system?

A (Dawes) Yes, both me and my team.

Q Can you provide just a general overview of your involvement with that process?

A (Dawes) Yes. So, less involved from a detail standpoint, so more so design-related decisions; ensuring training and testing took place, and that people on my team were generally available; as well as validating any information after cutover, to ensure that the cutover was accurate.

Q Okay.

A (Dawes) But the bulk of the details weren't necessarily performed by the people on my team.

Q And, then, Ms. O'Brien, would you please state your full name, position, and responsibilities?

A (O'Brien) My name is Erin O'Brien. I joined Liberty in September of 2020. I am the Accounting Director in the East Region, looking after general accounting for the New Hampshire companies.

My background, prior to joining Liberty, is I spent 14 years at PwC, most recently as the Director in the Audit practice. I have my Bachelor of Science in Business Administration from Stonehill College; my Master's in Accounting from Northeastern

University. And I am a Certified Public Accountant.

Q Great. And are you familiar with the Department of Energy's Motion to Dismiss and the Company's Objection to the Motion?

A (O'Brien) I am.

Q And are you also generally familiar with the Company's rate case filing?

A (O'Brien) Yes.

Q And you work with Mr. Dawes, correct?

A (O'Brien) Correct.

Q And, so, in that work, you were also involved in the SAP transition, is that correct?

A (O'Brien) That's right.

Q Including the training and validation out of the transition?

A (O'Brien) That's right.

Q Back to Ms. Read for a moment. The Company included a proposed exhibit regarding the SAP Chart of Accounts that was marked as "Exhibit 7". Did you prepare that exhibit?

A (Read) Yes, I did.

Q Okay. And, before I ask you a series of questions referring to that exhibit, I thought it would be helpful to define some of the terms that the Company will be using.

So, there's three sets of data that we've been discussing today. And the first is the Company's general ledger. Could you define what the "general ledger"?

A (Read) "General ledger" is a list of accounts that are primarily used for financial transactions. And the general ledger is used for financial reporting, internal management reporting, external reporting, regulatory reporting.

Q And, then, the second dataset we've been discussing this morning is the FERC Form 1. And I think what that is is self-explanatory. But could one of the witnesses please just explain briefly how the FERC Form 1 relates to that general ledger?

A (O'Brien) The general ledger provides the basis for the preparation of the FERC Form 1. We'll get into details today around any adjustments that were required. But the transactions present in the general ledger are the basis for the FERC Form 1.

Q And, finally, the third set of data we've been discussing are the Company's revenue requirement schedules. And could you explain how those schedules relate to the general ledger and FERC Form 1?

A (O'Brien) Similar to the FERC Form 1, the general ledger provides the basis of the transactions throughout the year in preparation of the initial test year for the revenue requirement.

Q Okay. And, so, now turning to Exhibit 7, at Page 3. Page 3 has a diagram. Do the witnesses see that?

A (Read) Yes.

Q And is that diagram intended to show that the SAP accounting system is just one component of the Company's IT investment that is sometimes referred to as "Customer First"?

A (Read) Yes.

Q Okay. And what functions does that SAP General Ledger Program serve?

A (Read) The general ledger, the SAP general ledger, is all the financial transactions recorded from the Company's perspective, and all that general ledger information is used and gathered in a way to be able to produce financial reports, as I mentioned before, around management reporting, external reporting, and regulatory reporting.

Q And what are some of the benefits associated with the Company's conversion to the SAP general ledger?

A (Read) Our systems, our legacy systems that we were using before were outdated, costly to maintain, and not fully integrated. We had a Great Plains system, which was our financial transaction system, our ERP system. We had Cogsdale, which was our customer information system, was a separate system that needed to bring data and financial transactions over, information over, in order to complete our financial data for the Company.

We also, through SAP, we now have a integrated system between customer service, financials, and operations. We also have found the SAP implementation is reducing manual work, especially from an accounts payable perspective, there's no more data entry. There were a lot of manual transactions done in our legacy systems to our intercompany billing and our allocations. Our fixed asset subledger is Power Plan, now is part of Customer First, and that provides a lot of automation, in terms of AFUDC calculations, which were done offline in Excel spreadsheets, instead of having it automated within the system. So, our SAP Customer First implementation was bringing more automation.

Q Thank you. And I'm just going to say, you might need to slow down a little for the court reporter.

A (Read) Okay.

Q I'm guilty of that as well. So, the Company has stated that the Customer First investments went live in October of 2022, and that included this SAP General Ledger Program.

If we refer to Page 4 of Exhibit 7, which is titled "General Ledger/Financial Data Conversion Process", is this a high-level overview of the process for implementing the SAP general ledger?

A (Read) Yes.

Q Okay. Could you provide just a brief explanation of that process?

A (Read) Sure. So, this just highlights four steps that the organization or Customer First, the Company, took in order to complete our data conversion of the data from our legacy system into our SAP system.

The first thing we needed to do is we needed to create and design an SAP Chart of Account. That's the foundation for any system ERP implementation, because those -- that Chart of Account provides the general ledger information from the financial transactions.

The second step we needed to do is we needed to convert the data from our Great Plains legacy system to SAP. So, the Great Plains Chart of Accounts, the different segments there needed to be mapped to the new SAP Chart of Accounts.

The fourth step is you needed to load -- sorry, the third step, third step you is you needed to load the data into SAP, because that's your starting point. That's where you have your historical balances, as well as your opening balance.

And, then, the fourth step is to validate, reconcile, and sign off on the data to ensure both systems have the appropriate data.

Q And, before we move on, you've used the acronym "ERP" a couple times. Can you just define that?

A (Read) Sure. Our "Resource Enterprise Planning".

Q Thank you. And, then, if we turn to Pages 5 and 6 of Exhibit 7, those provide a comparison of the Chart of Account structure under the legacy Great Plains system and the SAP system, is that correct?

A (Read) Correct.

Q Could you explain just a few of the key differences between those two Chart of Accounts?

A (Read) The Great Plains Chart of Accounts structure has six segments. Each of those segments were inconsistently used across our organization and our companies, which provided a little bit of some difficulty in making sure that one segment would be mapped to the new segment.

The one important change or difference from our Great Plains Chart of Account is the last three segments of our Chart of Account, our account class, natural account, and subaccount, those three segments added together were our -- what we called our "natural account/regulatory account", and that three segments determined our financial reporting, so, for GAAP reporting, as well as regulatory reporting.

Q And, if we move on to Page 7, which is titled "Legacy to SAP Conversion Process", there have been a lot of references to "mapping" and "conversion". Could you provide an explanation what is meant by "mapping" and "data conversion", as it pertains to moving data from the legacy system to the SAP system?

A (Read) I was kind of trying not to make it as complicated as it sounds. But it is a technical table configuration that we needed to be able to provide, to be able to say these are the accounts coming from Great Plains, these are the segments that they now map to in SAP. Then, we need to bring the balances. We did not bring over financial -- all the financial transactions from our legacy system, Great Plains, we brought over our account balances. So, every month we did a calculation of the amounts that were in those Chart of Accounts, in those accounts, and then brought it over into SAP.

We have a mapping table that shows

these are the source information, and this where the information needs to land in SAP. As an example, the Granite State mapping table that we had had over 1,100 rows of data. And we brought over twelve months of 2021 data and nine months of 2022 data in our opening balances for October.
Q And what steps did the Company take to verify that that process happened correctly?
A (Read) Every month we bring over the data, we do a reconciliation, to make sure that the balances were -- our trial balance, because it's a trial balance load, that comes into SAP, we ensured that it balanced. We did some spot checks to ensure that the net income, total net income, tied in SAP to Great Plains. And we did some spot checks on some balance sheet accounts, assets, as an example, net assets totaled, cash balances were correct, or equity tied.
Q Can you also explain how data has been mapped within the SAP system with respect to transactions that occurred starting in October of 2022, when the system went live?
A (Read) Yes. And that's going to the next slide, which is page -- Slide 8, it talks about the

regulatory account assignments.

What's important to highlight in SAP, every single financial transaction in SAP is reported to a natural account, as well as the regulatory account. Through SAP, the regulatory account derivation is done through custom mapping tables that are created in SAP. When a financial transaction is reported, SAP fetches the regulatory body, because Liberty has not just FERC Electric, Granite State is one of our utilities, we have utilities throughout the U.S. that have different regulatory bodies or jurisdictions, like NARUC Water and Sewer, as well as FERC Gas.

So, the account assignment in SAP, the regulatory body is derived based on the company code and the profit center, to determine, as an example, you must use FERC Electric as your regulatory accounts. Through that, it then goes to three different mapping tables that are created in SAP, depending on your account classification. So, for example, balance sheet and revenue accounts, we have a direct mapping table in SAP, which is a one-to-one natural account to regulatory account. The natural account will then need to go to the regulatory body to determine which regulatory accounts we need to use.

One thing I would like to mention about the regulatory accounts that are created in SAP, we looked at the FERC Uniform System of Accounts to determine completeness, and determined all the accounts that needed to be set up in SAP in order to do the regulatory reporting.

Q And, so, is that part of your verification for ensuring that that process was set up correctly?

A (Read) Yes.

Q Okay. And how did the Company validate that things were working correctly?

A (Read) We, through our testing process, we had some test cases and scenarios where we recorded transactions through SAP, and we determined the output, to make sure that the right -- appropriate regulatory account would be derived based on the transaction. So, the different transaction types, based on the natural account, to determine the appropriate regulatory account is then validated.

Q If we turn to Page 10 of Exhibit 7, that discusses issues with the mapping you just described to us, are you familiar with the adjustments that were made prior to closing the 2022 books?
A (Read) Yes.
Q And are you also familiar with the adjustments that were made following closing of the 2022 books?
A (Read) At a very high level, yes.
Q And what is the process to correct those? Or, I guess how were those adjustments identified?
A (Read) So, first of all, I think it's important to understand, some of the mapping that has been talked about today is related to -- some of it was related to data conversion, some of the opening balances from our legacy system to our SAP system did not get mapped to the appropriate account. One example, I think it's on the list of adjustments that were done, was related to an intercompany transaction. That data got mapped incorrectly to a asset intercompany account, instead of it being in a liability account.
Some of the other transactions or

adjustments that came through were related to transactional data that happened once we were live in SAP. So, as an example, you're starting to create new data in SAP, because you're using the system. One good example is we keep talking about "WBSs", which is called a "Work Breakdown Structure". That's similarly -- you can kind of think of it as a "project". Projects get created, and you need to ensure, if they're capital, they need to settle to the balance sheet; if they're operation and maintenance projects, they need to sit on the expense side on the P&L.

We also create these projects to settle and do intercompany allocations between our different companies, our service company and our Corporate service company, to charge costs to our utilities.

Q The --

A (Read) Those -- sorry.

Q No, go on.

A (Read) If those are not set up correctly, it will not derive the correct regulatory account. As I mentioned before, every single financial transaction in SAP is recorded to a natural account and a regulatory account. If incorrectly set up, the project incorrectly set up with the wrong settlement profile, it would cause the regulatory account to be the regulatory clearing account, which, as people have been speaking to, "999", the "999 regulatory account". If that process of creating those new structures or projects in SAP are incorrect, it could cause a incorrect regulatory mapping.

Q As an example of a new WBS, I believe is when a storm event occurs, right?

A (Read) Correct.

Q So, that's an example of something that would be new after the "go live", correct?

A (Read) Correct.

Q Okay. The 2022 books were not reopened to reflect adjustments identified after they were closed, is that correct?

A (Read) Correct.

Q And could you explain why the Company did not reopen the 2022 books?

A (Read) I guess it depends on timing of when certain adjustments are captured or identified, and how much time has passed since closing the books. And we close the books, it's best practice to close your financial ledger and stop transactions going into a past period. It's just best practice to close, make sure you close and you have that governance on closing. But a decision was made not to open them.

Q And we heard this morning that the Company acknowledged, at the last day of hearings, on January 4th, that there is one additional issue that will require adjustments to the revenue requirement in this proceeding.

Ms. Read, based on your understanding, do you expect there will be any additional adjustments related to SAP conversion, with respect to the 2022 books?

A (Read) Not that I'm aware of. But I would defer to Mr. Dawes and Ms. O'Brien.

Q Okay. And I have a few questions for them now. So, Mr. Dawes, did your team review the books and records prior to filing this case?

A (Dawes) Yes, can you be more specific?

Q Did your team perform a review of the general ledger before the case was filed?

A (Dawes) Yes. So, if we go back to the year-end books and records we needed to prepare the FERC Form 1, --

Q Uh-huh.

A (Dawes) -- so, it was at the time of the FERC Form 1 preparation that we determined that we needed to make some adjustments to the regulatory accounts, the FERC accounts. So, I'd say, I mean, that was when the thorough review was taking around the regulatory accounts. So, those adjudgments were made in the FERC Form 1.

But, also, subsequent to closing the books for 2022, we noted that there were some adjustments that needed to be made. I think there were four or five that we have brought forward in this case. But those were essentially found after the Corporate book closing process was completed. I think Luisa had mentioned that.

So, typically, it's a lengthy process to close your books, get all your financial statements prepared, all of your notes to your financials. You really can't book any new adjustments really beyond maybe three or four weeks after the end of the year. It just doesn't work in the process.

So, those adjustments we recognized really pertained to 2022 activity. So, we talked about "should we put them in the FERC Form 1?" I think those were even after the Corporate books were closed and the audit of the FERC Form 1 was completed, that it didn't make sense to try to push those into the FERC Form 1.

But we did realize that, since they were part of the 2022 results, they were a reduction in expenses, it made sense to incorporate those into the filing.

Q And this morning we heard a lot of reference to the "Audit Report". Did you participate in, or did you or your team, in responding to questions from the Audit Division?

A (Dawes) Yes.

Q And did you review the resulting Audit Report?

A (Dawes) Yes, I did.

Q And the Audit Report resulted in 28 Audit Issues, is that your understanding?

A (Dawes) Yes.

Q And is an audit report with 28 issues indicative of unreliable books and records, in your opinion?

A (Dawes) Yes, I would say, so, Audit Issue 1 was our adjustments that we identified. You know, Ms. Moran mentioned that they were -- "some were Staff's and some were ours", they were all our adjustments. So, those were the ones we made for the FERC Form 1 filing.

The others, I think there was an assorted number of them, some were related to SAP, many were not. I think the net impact on the revenue requirement coming out of those adjustments I believe was $250,000 or so.

So, there may have been a number of adjustments in the Audit Report, or audit issues, but certainly weren't significant to the overall revenue requirement or the 2022 financial results of Granite State.

Q And, as part of Audit Issue 1 in the Audit Report, the Audit Staff concluded that it could not determine whether the adjustments were accurate or if the adjustments identified were all of the adjustments that should have been done. So, as you just stated, Audit Issue 1 related to adjustments identified by the Company, and that were made prior to filing of this case,

correct?
A (Dawes) Correct. They were made prior to filing the FERC Form 1, which then became the basis for what was included in the case.
Q But, because those adjustments were made after the closing of the 2022 books, they were made between the closing and the FERC Form 1? Am I correct, that those would not be reflected on the 2022 books?
A (Dawes) That is correct.
Q We've heard a lot of comments about the volume of adjustments that have to be made. Do you expect that the number of adjustments will decrease, as the Company continues to gain familiarity and experience with SAP?
A (Dawes) Oh, most definitely. We've certainly learned an awful lot. We made a -- we made a number of corrections, obviously, as a result of this case, and what we found prior to filing the FERC Form 1. We've corrected the mapping issues.
And I would say, for the end of 2023, we don't anticipate any more adjustments from mapping issues, particularly associated with 2022. And the 2023 final books and records

should match the FERC Form 1.

So, I would envision that there -- I mean, there's always going to be issues in any year. But the issues we're talking about in this case, I don't anticipate going forward. I mean, someone could always set up a WBS incorrectly that settles to the wrong regulatory account, and we might have to make a correction at a later date. But that's no different than our legacy system. There's also the opportunity for something like that to happen.

Q A number of adjustments related to 2022 were not reflected in the 2022 books, because they had been closed. Is that unusual, in your opinion, to identify and make adjudgments after the fiscal year accounting has closed?

A (Dawes) It's not uncommon. I mean, --

[Court reporter interruption regarding use of the microphone.]

CONTINUED BY THE WITNESS:

A (Dawes) Sorry. It's not uncommon. I don't know if I'd call it "standard practice". But, I mean, any time you close the books, and you've got a relatively short period to close everything off, identify any adjustments that you can put into the final books. Occasionally, there are things you do find after that. And, to the extent they impact the balance sheet accounts, you would want to make those adjustments, if at all possible.

BY MS. RALSTON:

Q And, in your opinion, excuse me, with these adjustments, and the explanations the Company has provided, that allow for tracing from the 2022 general ledger, to the FERC Form 1, to the revenue requirement schedules, has the Company provided reliable data in this proceeding?

A (Dawes) From what I understand, yes. I mean, they're not part of the actual filings themselves. But, from what I understand, we have provided sort of the path from the books and records, through the FERC Form 1, and the additional adjustments. And I think we made an update filing in November that provided information on all of the updates that we made.

I think the only final item would be the additional adjustments that we've been talking about this morning.

Q Great. And, Ms. O'Brien, I believe that you worked directly with the Audit Division during their investigation. What steps did your team take to assist with that review?

A (O'Brien) In May of 2023, recognizing that we had the new system in place, we had a meeting with Audit Staff to discuss the new Chart of Accounts, the differences from how the account numbering, our company numbers changed, you know, just and taking them back and walking through what our new company numbers were and what the accounts would look like, so the Audit Staff would be aware of those differences.

Throughout the audit, we responded to audit requests as they arose, and worked to provide explanations to those questions.

Q And, during the first day of hearings on January 4th, we heard from counsel for Department of Energy that there were "hundreds of adjustments made to the Company's general ledger".

If I refer you to Exhibit 6, which is the Company's November revenue requirement update, specifically the file that's labeled "Part 2", and there's a tab that we discussed this morning that's called "TrackRRUpdates", is the purpose of that tab to show the updates made to the revenue requirement and provide the reason for the update?

A (O'Brien) Yes, and cross reference as well.

Q And Row 7 says, under the "Notes", that the adjustments are "As filed". Does that mean that those adjustments were included in the Company's filing submitted in May?

A (O'Brien) Yes.

Q And are those adjustments the same adjustments identified in Audit Report Audit Issue 1?

A (O'Brien) Yes.

Q And those issues were identified by the Company, correct?

A (O'Brien) That's correct.

Q And they were identified before the filing of this docket, just to be clear?

A (O'Brien) That's correct.

MS. RALSTON: Okay. That's all I have. Thank you.

CHAIRMAN GOLDNER: Thank you. We'll move now to DOE cross, and Attorney Dexter.

MR. DEXTER: Good afternoon.

CROSS-EXAMINATION

BY MR. DEXTER:

Q I believe I heard testimony from the panel that you had reviewed the Audit Report that was issued by the Department of Energy in October 2023, is that right?

A (O'Brien) Yes.

A (Dawes) Yes.

Q And do you dispute the results or the findings of that Audit Report, other than the Company comments that are noted therein?

A (O'Brien) No.

Q I wanted to go over the chronology of the filing of the FERC Form 1 and the filing of the rate case for a minute. And just -- you can just help me see if I have this right.

So, I have a letter here from Liberty dated April 11th, to Chairman Goldner, indicating that Liberty had requested an extension of time for filing its FERC Form 1 until May 31st, 2023. Does that sound right to you?

A (O'Brien) It does.

Q Okay. And, then, Liberty filed its FERC Form 1 -- well, I'm sorry, on April 28th, Liberty

made a rate filing, correct?
A (O'Brien) Yes.
Q In this docket?
A (O'Brien) Yes.
Q April 28th, okay. And, on April -- on May 2nd, that Rate Filing was rejected by the Commission, because it referenced a FERC Form 1 that was not yet on file. Is that your understanding?
A (O'Brien) That's my understanding, yes.
Q Okay. And, then, subsequently, on May 5th, the Company filed its FERC Form 1 with the Commission and the Department, is that right?
A (O'Brien) That's right.
Q And that's the same date that you filed the case, which is the one that we've been working on in this docket?
A (O'Brien) Yes.
Q Okay. And, then, on May 19th, the Company refiled it's FERC Form 1, is that right?
A (O'Brien) That's right.
Q And can you explain why there was a refiling of the FERC Form 1 on May 19th, and how it differed from the one that was filed on May 5th?
A (O'Brien) The FERC Form 1 for Granite State

Electric requires an independent audit review. The timing of the preparation of the FERC Form 1 did not allow for that to be completed prior to the May 5th filing. As a result, the audit -- the external auditors were provided that FERC Form 1 for audit. My understanding is that the FERC compliance rules allow for the independent audit report to be filed within a certain period of time after the initial filing of the FERC Form 1. So, it was resubmitted in mid-May of 2023, with the audit report included.

Q Okay. And did any of the balances in the accounts change between the May 5th filing and the May 19th filing, or was it more to include statements from the external auditors?

A (O'Brien) It was more to include the statements from the external auditors. I would need to go back and compare one-for-one. But there were no -- certainly no significant changes.

Q Okay. And, so, I have one page of the FERC Form 1 in front of me. And there's a statement that's made by Peter Dawes. I'll just read it into the record. But, if you want to follow along, follow along. I'm looking at the FERC

Form 1 from May 19th. And I'm looking at Page 6 of 163. And it's called "Annual Corporate Officer Certification. And it says "The undersigned officer certifies that I have examined this report, and to the best of my knowledge, information and belief, all statements of fact contained in this report are correct statements of the business affairs of the respondent, and the financial statements and other financial information contained in this report conform in all material respects to the Uniform System of Accounts." And there's an electronic signature of "Peter Dawes, May 18th".

So, that's you, Mr. Dawes, correct?

A (Dawes) Correct.

Q And are you -- so, you're familiar with that statement?

A (Dawes) Oh, yes.

Q And is that statement accurate, as you sit here today?

A (Dawes) So, when the FERC Form 1 -- excuse me. As of the time of the filing, to my understanding, that was an accurate depiction of the FERC Form 1. So, that statement was correct.

I mean, I would say today, it was materially correct. I mean, I would be comfortable making that same statement. I know we found certain adjustments, but nothing would be material to make me alter what I put in for a certification on that FERC Form 1.

Q Okay. And this statement in this FERC Form 1 was prepared, I think as you just indicated, after the numerous adjustments that were discussed in Audit Issue 1, this came after that, correct?

A (Dawes) The adjustments in Audit Issue 1 were part of the FERC Form 1. So, yes. I don't know if I would characterize it as "numerous". But the adjustments, yes, were part of that.

Q So, in the Audit Report, I -- I didn't count them line-by-line, but I came up with about 200. Would you agree with that number, that it was in the area of 200 adjustments that were made to the books, to take you from the books to the FERC Form 1?

A (Dawes) I think I'll let Ms. O'Brien answer that one.

Q Sure.

A (O'Brien) I would not agree with that

characterization. The adjustments that were recorded were part of one analysis that was performed over the books and records. And the items listed in Audit Issue 1 show, in most cases, both the debit and credit side of the adjustment that was reported, therefore are captured at least twice, in some cases more, as detailed line items total an amount already included in the report.

Q Okay. So, you wouldn't consider those "numerous"?

A (O'Brien) I would not consider there to be over 200 adjustments.

Q Okay.

A (O'Brien) I believe it impacted sixteen account lines.

Q Okay. Would you say that -- and I asked this question of Ms. Moran earlier this morning, and said I'd come back to you guys with it. Would you consider the FERC Form 1 that was filed and certified to be more accurate than the books that were closed, the internal books that were closed at the end of the year? In other words, were they improved by these adjustments that were

made?
A (O'Brien) Absolutely.
Q Okay. And that's what allowed Mr. Dawes to sign the statement that "the reports are correct" -- "correct statement of the business affairs, and the financial statements and other information contained in this report, conform in all material respects to the Uniform System of Accounts"? Those adjustments that you made gave credence to you being able to make that certification, I guess is what I'm asking?
A (Dawes) Yes.
Q Okay. Now, in the rate case that was filed on May 5th, there's an attestation also filed by Mr. Dawes. And it appears at I-182 in the filing, which is part of the Company's filing requirements.
And I have paper copies, if it's hard to find. But it's I-182 in the Company's filing requirements.
Are you familiar with that attestation, Mr. Dawes?
A (Dawes) I do not have it in front of me. But I recall signing that attestation.

MR. DEXTER: Okay. Well, I was going to read from it. But, Attorney Ralston, I have paper copies, if you want to provide it to the witness.

CMSR. SIMPSON: Attorney Dexter, can you reiterate what part of the filing you're looking at?

MR. DEXTER: Yes.

CMSR. SIMPSON: If you have a tab from the docket, that would be helpful. Thank you.

[Atty. Ralston handing document to Witness Dawes.]

MR. DEXTER: So, it's Tab 5. It's Tab 5, and -- sorry, Tab 11, in the May 5th filing, it's called "Filing Requirements". And, if you go into that, they're all designated with a "I", and then it's followed by -- the actual page number is "I-182".

CMSR. SIMPSON: Thank you.

BY MR. DEXTER:

Q And it's just called "Attestation". I think it actually intends to cover two certificates that are required by the rules. But, Mr. Dawes, maybe you could just explain what this attestation does?

A (Dawes) Okay. So, there are certainly two parts to it. And I'll maybe skip over the second part, because I think you're focused more on the first one.

So, it's getting at the information filed in support of the rate case is supported by the books and records of the Company. And, in signing the attestation, certainly, I attested to the FERC Form 1, since I had to certify that. And I was aware that we made other adjustments that I think I had talked about a little earlier, that didn't get into the FERC Form 1, but were part of the actual filing. So, I felt comfortable attesting to what was filed in the rate case was accurate as far as its relation to the FERC Form 1, and those other adjustments that we made.

Q Okay. Well, let me just -- let me just go to the specific document. And it says "I affirm...the cost and revenue statements and supporting data submitted, which purport to reflect the books and records of Liberty Utilities...do in fact set forth the results shown by such books and records." So, that's an accurate statement, as you sit here today, correct?

A (Dawes) Yes. And "books and records", from my standpoint in attesting to this, was what was part of the FERC Form 1. Not necessarily what was in the trial balance at the end of 2022, which we know was different than what was in the FERC Form 1.

Q And, then, it goes on to say that "all the differences between the books and the test year data...have been expressly noted." Could you explain to me where the difference is between the Company's books and records and the rate case information was "expressly noted"?

A (Dawes) So, as I mentioned earlier, I was going from the standpoint of the FERC Form 1 being really the books and records, not the trial balance. So, in my view, there were no differences.

But I certainly appreciate that we didn't -- we didn't put in those additional adjustments that weren't part of FERC Form 1. So, I would agree that those could have been called out.

Q Okay. Well, let me -- so, let me break this down then.

So, if we consider that "books and records" means the "FERC Form 1", could you explain where the difference is between the FERC Form 1 and the rate case statement, the rate case information, where was that detailed in the rate case?

A (Dawes) Where was what detailed? I'm sorry.

Q The difference between the FERC -- any differences between the FERC Form 1 and the rate case information, the revenue requirements, the cost of service schedules, that were filed in the case?

A (Dawes) So, I think it would be the -- so, I think we had four or five adjustments that we -- I'm not sure when those were actually brought forward in the case, probably a little later. And I'm not sure, I would have to speak with Regulatory, but I'm not sure if those were detailed in the filing as being the difference between the books and records or FERC Form 1, and what was in the filing.

Q Anybody else on the panel want to -- can point to that in the filing?

A (O'Brien) I don't believe it was in the Initial Filing.

Q Okay. Now, if we take a different definition of "books and records", and include that to mean the "general ledger", where were the differences between the general ledger and the information that was submitted in the rate case? Where are those expressly noted in the Rate Filing?

A (Dawes) So, that's more of a hypothetical question, because I think I already answered that my basis was "the FERC Form 1 is the books and records." So, I mean, they wouldn't be there, using what you're getting at in your question, they wouldn't have been part of the filing.

Q Okay. So, any differences between the general ledger and the rate case sheets were not expressly noted?

A (Dawes) Correct.

Q Okay.

A (Dawes) As far as I know.

Q Okay. Now, the differences between the general ledger and the rate case would include the various adjustments we've been talking about in

Audit Issue 1, correct? Those were differences between the general ledger and the rate case?
A (Dawes) Correct.
Q Okay. And the differences between the FERC Form 1 and the rate case, where have those been captured in the course of the rate case, as it's unfolded?
A (Dawes) Erin, is that something you could answer?
A (O'Brien) It's been captured through various data requests, including the exhibit you presented at the January 4th hearing, as well as certain tech session requests, I believe, including 2-20.
Q Okay. So, the first part of your answer was the data request that I provided at the other -- at the January 4th hearing, which has been marked as "Exhibit 4". So, that was -- that was answered in October. So, well after the rate case was filed, correct?
A (O'Brien) That was provided in October, correct.
Q I didn't hear that.
A (O'Brien) I'm sorry. That was provided in October, correct.
Q In October. And these issues that were detailed in Exhibit 4, on Page 2 of Exhibit 4, they

actually appeared in the Audit Report, which was issued in October. So, that would give us some indication of when they were detailed. But the point is, it was all done after the filing, after the May 5th filing?

A (O'Brien) I believe so, yes.

Q Yes. Well, is there any indication that would cause you to believe otherwise?

A (O'Brien) Not that I'm aware of.

Q Okay. Mr. Dawes, what's behind the distinction that you've drawn in your answer, in characterizing the "books and records" as meaning the "FERC Form 1"? What would lead you to make that distinction?

A (Dawes) So, I would say, typically, it's the FERC Form 1 and its balances are the starting point for a rate filing. So, in my experience, which includes 20 plus years being a revenue requirement witness, it always starts with the FERC Form 1.

Q Okay. So, I've got the testimony here of Jardin and Dane from this rate case. I read this on January 4th, I'll read it again.

MR. DEXTER: And I'm on Page II-276, if

the Commission wants to follow along.

CMSR. SIMPSON: The testimony of?

MR. DEXTER: It's the Testimony of K. Jardin and D. Dane.

CMSR. SIMPSON: Tab 11?

MR. DEXTER: Yes. That would be Tab 11 again.

CMSR. SIMPSON: And I'm sorry, the page number?

MR. DEXTER: So, they're all IIs in this section. So, it's "II-276".

CMSR. SIMPSON: Thank you for that.

BY MR. DEXTER:

Q And the question that was asked in the written question was: "What approach did you use to determine the revenue requirement and the revenue deficiencies?"

And the answer was: "The Company began with the unadjusted Test Year financial results and made the adjustments described below to calculate *pro forma* Test Year and Rate Year revenue requirements and revenue deficiencies."

Sorry to keep reading, but I think it's the fastest way to do it.

And, then, the new paragraph says: "Test Year". "Our analysis began with the Company's financial results in the Test Year (i.e., the twelve months ending December 31st, 2022)."

So, Mr. Dawes, is it your understanding that, when the witnesses said that, the "financial results", they weren't referring to the books and records of the Company, they were referring to the FERC Form 1?

A (Dawes) I'm not familiar with that data response or the context with how the question arose.

Q Okay. Well, I'm not --

A (Dawes) I'm not sure -- I'm not sure what they were thinking when they were answering that.

Q Okay. Well, it's not a data response. It's the Company's testimony, just to --

A (Dawes) Okay. I'm not familiar with that either.

Q Okay. So, you said earlier, in your "20 years of doing rate cases, the starting point is the FERC Form 1, not the Company's general ledger." Did I understand that right?

A (Dawes) You did.

Q Okay. All right. But you don't know what the witnesses were referring to when they said "we started with the financial results"?

A (Dawes) I'm assuming they meant the "FERC Form 1". I mean, that was the basis of -- the starting point for the revenue requirement was the FERC Form 1.

Q And I think I heard testimony earlier on from the panel that "everything starts with the general ledger, and that feeds into the FERC Form 1". You agree with that, correct?

A (Dawes) Oh, yes. Correct.

Q Okay. And, if you're going to look at the underlying transactions in a test year, you can't look at the FERC Form 1, because that just gives you the balances, correct?

A (Dawes) Correct.

Q And, if you want to know what makes up those balances, you have to go to the general ledger and see what the various financial transactions are, correct?

A (Dawes) Yes.

Q All right. So, this testimony goes on to say: "From those results, we removed flow-through items", and it's "(purchased power and transmission wheeling...), and made *pro forma* adjustments for known and measurable adjustments. The resulting Test Year *pro forma* net operating income reflects normalized revenues at current rates and expenses, and net operating income for ratemaking purposes."

It doesn't say anything in here about the adjustments that were made to take us from the general ledger to the FERC Form 1, does it?

MS. RALSTON: Mr. Dawes is not the witness for this testimony. And it wasn't marked as an exhibit. So, I know he's doing his best, but this probably beyond his expertise area.

CHAIRMAN GOLDNER: Attorney Dexter.

MR. DEXTER: Well, I'll take an answer from anyone on the panel, or counsel, or anybody in the audience that knows. It's a fairly simple question.

CHAIRMAN GOLDNER: Does anyone on the witness panel know the answer to Attorney Dexter's question?

WITNESS DAWES: Do you mind asking it one more time please?

BY MR. DEXTER:

Q Yes. I guess what I'm saying is, this testimony, Page 276, where it talks about the development of the Test Year, makes no mention of the adjustments that were made to go from the Company's books and records, to the -- to the Test Year results that were presented -- I'm sorry, to the revenue requirement results that were presented in the rate case. Would you agree with that, that it's not mentioned in this testimony here?

MS. RALSTON: I think Mr. Dawes could agree on what the page says. But, if we're going to get into how this testimony was developed, I mean, he's not the right witness. And there was an opportunity to mark this as an exhibit, and the Department of Energy did not do that.

CHAIRMAN GOLDNER: Attorney Dexter.

MR. DEXTER: Well, I'm not sure what the objection is. I think counsel is objecting to a question I haven't asked question yet, which was going to be my next question.

But I just simply asked "does this testimony talk about the adjustments that were made, to go from the books to the rate case filing?"

And, if nobody at Liberty can answer that question, I guess that's what we're left with then.

MS. RALSTON: Well, I agree. We can -- we can agree to what the page says. I just wanted to point out that this is not the revenue requirements witness.

So, yes. The page does not reference the FERC Form 1. I don't know what else we can say on that.

CHAIRMAN GOLDNER: Attorney Dexter, how would you like to proceed?

BY MR. DEXTER:

Q I guess I would like to ask the panel of witnesses, is there anywhere in the rate case that was filed that details the differences between the general ledger and the FERC Form 1 that were the issues that were highlighted in Audit Issue Number 1?

If the panel can answer that, then --

CHAIRMAN GOLDNER: And the Commission would also be interested in that answer. So, --

BY THE WITNESS:

A (O'Brien) So, I don't believe there is anywhere where we have outlined the bridge in our rate case filing from our SAP general ledger to the FERC Form 1 and the revenue requirement. We took the books and records to meet the FERC Form 1, and have worked through the FERC Form 1 to the revenue requirement.

BY MR. DEXTER:

Q Okay. So, I want to go to Exhibit Number 5, which is Record Request Number 1, Record Response Number 1 for a minute. This exhibit indicates that the respondents are "Erin O'Brien" and "Peter Dawes", is that right?

A (Dawes) I don't have that in front of me.

CHAIRMAN GOLDNER: Exhibit 5, Attorney Dexter? Would counsel for Liberty be able to approach the witness and provide Exhibit 5 for them please?

MS. RALSTON: Yes.

[Atty. Sheehan providing his laptop to the witness panel for document view.]

WITNESS DAWES: I apologize. I know that counsel sent me the email that had the exhibits, but I can't get into my email. So, it does me no good. Sorry for that.

CHAIRMAN GOLDNER: No problem.

BY THE WITNESS:

A (O'Brien) Yes. We are the respondents.

A (Dawes) Yes.

BY MR. DEXTER:

Q Okay. So, I would like to go to Issue Number 5, which is on Page 2 of Exhibit 5. And, in the far right-hand corner, there's a description -- well, first of all, why don't I ask you, what is Exhibit 5 intending to show?

A (O'Brien) We were asked to provide the top ten adjustments, and that is what this is intending to show.

Q Okay. Could you just be more specific what you mean by "adjustments"?

A (O'Brien) So, these are the top ten largest adjustments that were required to the regulatory accounts, from the general ledger to the revenue requirement filing.

Q Okay. To get you from the general ledger to the revenue requirements filing?

A (O'Brien) Yes.

Q Okay.

A (O'Brien) The regulatory account general ledger.

Q Okay. So, Item Number 5 and Items Number 8, 9 and 10, are all dated "December 2023", would you agree?

A (O'Brien) Yes.

Q Okay. And Item Number 5 says that, essentially, and if I'm misstating this, you can tell me, that there was $527,000 that should have been recorded to Account 593, FERC Account 593, but was actually recording in Account 920. Is that right?

A (O'Brien) That's right.

Q Okay. What's "920"? That's an Administrative & General expense account, isn't it?

A (O'Brien) Yes.

Q What's "Account 593"?

A (Dawes) It's certainly an Operation & Maintenance account. It's not an Administrative & General. But I'm not sure specifically what "593" is, without looking at the FERC Chart of Accounts.

Q Sure. Which, feel free to, but I'll accept that it's an Operation & Maintenance expense account.

A (Dawes) Yes. It is.

Q Okay. And, so, at the bottom of the explanation, it says that "The impact on the revenue requirement has not been calculated, but it will be driven by the difference in the escalation factors applied to FERC 920 versus FERC 593." Can you explain what that means?

A (O'Brien) We identified a number of adjustments in December 2023, as we've discussed. I would like to mention that the net impact of those is only $167,000. So, we have taken the absolute value of the differences in preparing this top ten analysis for the Commission.

The intent of the statement here is to identify that this does not mean there is a $527,000 impact on the revenue requirement. It will need to be run through the calculation for that to be determined.

Q Okay. Because, and I think this came up a lot at the January 4th hearing, you know, if an item is in the wrong expense account, that's one thing. But an expense is an expense, generally speaking, for revenue requirements. So, the impact is zero or minimal, is that what you're saying?

A (O'Brien) That's the expectation.

Q Yes.

A (Dawes) So, test year impacts would be what is shown. But, certainly, if you're doing a known and measurable, you need to escalate, whether it's labor, non-labor, that still needs to be determined what those impacts are.

Q Okay. And that's what the -- the statement about the "different escalation factors" pertains to?

A *[Witness Dawes indicating in the affirmative]*.

Q And you haven't done that calculation?

A (O'Brien) We have not.

Q Okay. So, similarly, on Adjustment Number 8, this is a $243,000 adjustment, also discovered in December 2023. And this says that an item was recorded to Account 920, which, again, is an administrative expense account. And it says "however subsequent review determined that the balance should have been recorded to various income statement FERC accounts", but they're not identified.

Do you know which income statement FERC accounts this should have been put into?

A (O'Brien) Between A&G and O&M, it was just more than one or two list. We do have that, though.

Q I'm sorry, I didn't understand that answer. So, do you know what accounts they should have been put into?

A (O'Brien) Not off the top of my head. But we -- but, as a company, we do have that information, yes.

Q Okay. You have the information, but you didn't provide it, and you don't know what it is?

A (O'Brien) Not off the top of my head, I do not know what it is.

Q Okay. But you know it's an expense account?

A (O'Brien) Yes. It was through various expense accounts.

Q Okay. Because it says "various income statement accounts", I'm curious whether or not it's possible these should have been mapped to revenue accounts, which would also be income statement accounts, correct?

A (O'Brien) I would need to get back --

[Court reporter interruption.]

BY THE WITNESS:

A (O'Brien) Sorry. I do not know off the top of my head, no.

BY MR. DEXTER:

Q	Okay. And, then, if we jump down to Item Number 9, again, we're talking about items that went to 920, but a "subsequent review determined that the balance should have been recorded to various income statement FERC accounts." Again, those accounts aren't specified. So, it's possible they could be revenue accounts?

A	(O'Brien) It's possible.

Q	Okay. And, then, Item Number 10, you say the item went to "920", but it should have gone to "Account 921". So, there you have the specific account. What's "Account 921"?

A	(Dawes) It's another Administrative & General account, but it's not salaries.

Q	Okay. And that's why the escalation factor could play into quantifying the revenue requirement impact?

A	(Dawes) Correct.

Q	Okay. Now, I think I heard the panel say that these were discovered in December 2023. How were these discovered, and what prompted their discovery in 2023, in December of 2023?

A	(O'Brien) So, we discussed the "999 account", and I believe Ms. Read mentioned it earlier as well.

So, when our system is deriving our FERC regulatory accounts, there are instances where it sometimes goes to this 999 account, which we know is not a true regulatory account, and needs to be cleared and determined where the appropriate regulatory account is. This is an exercise that's done at each month-end. In doing that exercise, at the end of 2023, we performed an analysis of the Account 999 balance, and determined where the reclassification entries were required. We got down to I believe it was $7,000 or so, in that neighborhood, and determined that Account 920 was the most appropriate locations for those remaining balances.

Throughout the audit and data requests, we identified balances sitting in -- that were part of that reclassification to 920, that were larger than the $7,000 that we had previously identified, leading us to understand that there were offsetting debits and credits that netted down to a small amount, but required further analysis. So, through that additional analysis that was completed in December, these adjustments were identified.

It's been a learning in the system. It's now something that we're capturing in each month-end, and have correct for 2023 as well.

Q   So, were adjustments made on the books and records of the Company, by that I mean the "general ledger", to reflect this discovery?

A   (O'Brien) In December 2023?

Q   Well, that was going to be my next question. My first question was, were there adjustments made?

A   (O'Brien) To which period?

Q   Well, that's my question. So, first of all, when you discovered these errors --

A   (O'Brien) We did not -- we did not reopen the 2022 general ledger. We have not reopened the 2022 general ledger.

Q   Okay. So, let me start again, then. So, there were four adjustments that we just went over that were discovered in 2023. So, my simple question first is, did that prompt Liberty to make adjustments on its general ledger to correct for this discovery?

A   (O'Brien) We have corrected, with regards to this discovery, as it's applicable to 2023. So, we are not recording any 2022 expenses, for example, in 2023.

Q No, I understand that. But you didn't -- you made an adjustment in 2023, is what you're saying?

A (O'Brien) To correct any similar issues related to 2023, yes.

Q Okay. But not for these specific dollar amounts?

A (O'Brien) Not for -- no. These are for a prior period.

Q Okay. Did you make any adjustment to the books in 2024, when these were discovered?

A (O'Brien) These were discovered in 2023?

Q Right.

A (Dawes) The books aren't open in 2024 yet. We're still closing out 2023.

Q Okay. So, there's been no adjustments made to 20 -- there are no books for 2024?

A (Dawes) Yes, and there won't be. These adjustments won't be in 2024. Any of the mapping updates or things that have been identified here that apply to 2023 will be updated with the 2023 books and records at the end of the year.

Q Okay. And would the same be true of the various issues that were identified in FERC -- I'm sorry, in Audit Issue Number 1, the numerous, I call them "numerous", you said "they're not numerous", those adjustments, those were made to the books of 2023, do I understand that correctly?

A (O'Brien) So, similarly, they were corrected in 2023, as they relate to 2023, for example, if there was a change to a balance sheet account. But there were no income statement items from 2022, recorded in 2023.

Q Okay. So, for example, just to beat this to death, sorry, Item Number 5, on Exhibit 5, the total amount was $527,000, that should have been in Account 920 -- that went to Account 920, but should have been to Account 593. No adjustment in the amount of $527,000 was made for this error in either the books of 2022 or 2023, do I understand that?

A (O'Brien) Not within our general ledger system, that is correct.

Q Okay. But, systematically, in other words, if there was a problem, then you made a change to the system, so that this wouldn't happen again in 2023?

A (O'Brien) That's correct. And, if there were any instances of an issue taking place in 2023, prior to system corrections, those are manually adjusted as well, to ensure the 2023 results are accurate.

Q So, could you just say that last part again please?

A (O'Brien) So, if identify a root cause of a system issue, for example, these -- if there was a WBS that was set up, and it's settling to a 999 regulatory account, and we corrected that, say, in June, if any charges were recorded to that WBS prior to the correction in the system, we would record a manual journal entry to correct that.

Q All right. Now, I'm very confused then. So, when would the manual journal entry have taken place? What year's books would that have affected?

A (O'Brien) Only the current year.

Q So, in that instance, 2023?

A (O'Brien) Yes.

Q Okay. So, now, getting back to the issues that were identified then in Audit Issue Number 1, those manual adjustments were made to the books,

if I understand what you're saying, were made to the general ledger in 2023?
A (O'Brien) As they apply to 2023, yes.
Q But not as they apply to 2022?
A (O'Brien) That's correct. Not as they apply to 2022.
Q Okay. I think I understand. Thank you.
A (O'Brien) There are no 2022 transactions recorded in 2023. If there are root cause issues, those are -- those have been corrected in 2023.
A (Dawes) Yes. And I would also just add, with these so-called "999 accounts", we have a monthly process that we put in place in '23, to provide and make sure those are getting reconciled and cleaned out and put in the appropriate regulatory accounts on a monthly basis.
Q Okay. So, Mr. Dawes, I think I heard you say earlier that you expect that the 2023 books will more closely match the FERC Form 1, well, now you've drawn a distinction between "books" and "FERC Form 1". So, now I have to change my question.
A (Dawes) I don't think you need to change your question.

Q So, I think I heard you testify earlier that, in 2023, the Company will require fewer adjustments from the general ledger to the FERC Form 1 that it required in 2022. Did I understand that right?

A (Dawes) Most definitely, yes. I'm sure there will be some customary reclassifications that we might do in the ordinary course. But nowhere near the adjustments that we made in 2023 for 2022.

Q Okay. So, would you say then that you think the mapping issues that we've been talking about are largely behind the Company at this point?

A (Dawes) Yes.

MR. DEXTER: Okay. So, I have some more questions about the slide show. It would probably take about ten or fifteen minutes. Should I proceed or --

CHAIRMAN GOLDNER: I think so. Let's move through all of your questions, Attorney Dexter. Then, take ten or fifteen minutes, and then move to Attorney Kreis.

MR. DEXTER: Okay. Thanks.

BY MR. DEXTER:

Q So, I'm looking at the -- I'm calling it a "slide show", I guess it's Exhibit 6 **[**Exhibit 7**?]** that talked about the SAP conversion. And I'm on Page 6 of 12.

MS. RALSTON: I think you're referring to "Exhibit 7".

MR. DEXTER: "Exhibit 7". Thank you, counsel.

BY MR. DEXTER:

Q Exhibit 7. And there's a statement at the bottom, in the tan box at the bottom of Page 6, that says "one natural account" -- well, let me read the whole thing. It says "Balance sheet & revenue accounts - one natural account to one regulatory account relationship via mapping." What does that mean?

A (Read) I'll take that question. So, if you go to -- it's further explained in Slide Number 8, that talks about the regulatory account assignment, where balance sheet and revenue account are based on a direct mapping table in SAP. So, a natural account is mapped to a regulatory account, based on the regulatory body, determined via the company code and profit center, to determine the regulatory body associated with the utility.

Q Okay. Now, back up to Page 6, there's a statement at the top of that page, in a gray box, and it says "Every transaction in SAP is identified to a natural account and a regulatory account." So, what does that mean?

A (Read) Every financial transaction in SAP has a regulatory account -- sorry, excuse me -- has a natural account, and the regulatory account is derived based on the tables created in SAP to derive the regulatory account. But every transaction is posted to both segments. Actually, it includes more segments. But, more importantly, I think, for people in the hearing today to understand, it's the regulatory account and the natural accounts are recorded every time a financial transaction is recorded in SAP.

Q Okay. And I heard a couple of times that there was a lot of testing done during the implementation of SAP. Can you describe that -- well, first of all, where any of you on the panel involved in the testing?

A (O'Brien) Yes. Or, our team did the testing.

A (Dawes) No, I was not part of the detail test.
A (Read) Yes. Me and my team under me were included in the testing.
Q Okay. Can you describe the testing that took place?
A (Read) Well, we tested all the processes within SAP by putting in transactions in our test environment, all the way down to a specific scenario. So, as an example, entering time sheets. So, we got employees to record time sheets, enter time data, recording it to projects, WBSs, which is our Work breakdown Structure, recording time to capital, versus operating and expenses.
We did manual transactions. We recorded vendor payments, invoices, POs, purchase requisitions. After all that data is input into the system, we then run, as part of our month-end close process, we also tested the month-end close process in SAP, where we closed out the books and we run financial statements.
Q And you did all that, as the name implies, testing, before the October 1st "go live" date of the system, is that right?

A (Read) That's correct.

Q Did the tests reveal any of the mapping issues that we've been talking about today?

A (Read) We did find some, we called them "defects", through the testing, where we would see, through the mapping table, an incorrect regulatory account was put in the table. So, we would record a defect, and we would go into the table and correct it.

Q Were they numerous or one or two, or do you recall?

A (Read) I don't recall exactly how many, but there were some. It's not like we didn't see any defects. We did see some that were corrected.

Q What do you attribute -- to what do you attribute the fact that the mapping issues that we've been talking about were not caught by the testing, if you will, identified by the testing?

A (Read) Some examples of incorrect mapping is related to new data being created in SAP once you're live. We did training, we did, you know, provide a job aid to explain what -- because not everybody in the organization could create projects, WBSs. There's only certain individuals who are trained who have access to do that. From our experience, what we have noticed through these adjustments is these projects have been created incorrectly once we were live in SAP; missing a profile settlement that didn't get updated correctly or get created in the right spot. So, that determined that there was a mistake in creating the Work Breakdown Structure once we were live in SAP.

Q Now, I think in your earlier testimony, you said something to the effect of you "took twelve of balances for 2021 and nine months of balances for 2022 in the old system, and you transferred those over to the new system." Do I have that right --

A (Read) Correct.

Q -- simplistically?

A (Read) Yes.

Q Okay. Did you identify any issues in the transfer of those historic balances, 2021 and the first nine months of 2022, did the testing identify any problems with the transfer of those balances?

A (Read) So, I will say, from the review and the balancing, because we had to balance the trial balance in both systems, we needed to verify and compare the net income from both systems were correct, we did identify some differences where we updated the mapping table, the data conversion mapping table, to put the appropriate "SAP", either natural account or regulatory account. And, then, we would reload the data to get the balances correct.

Q So, on Page 9, there's an entry on the right-hand side of the account that says "Primary Expense Accounts". And it says "House Allowance", and on the right-hand side it says "Employee Pensions and Benefits-FERCE". What is that? What's the "House Allowance"? What would this be recording?

A (Read) All right, to be honest, I don't know what exactly it's recording. What this is showing is what the mapping table looks like in SAP. You would have the natural account, plus the functional area, which functional area in SAP is defined as a "Cost Center" and a "Work Breakdown Structure". Those two fields together will point SAP to this primary expense derivation table, and it will produce -- it would show you which regulatory account the transaction would be

posted.
Q So, this is --
A (Read) This is just an example of a mapping table.
Q Sure. But, under this example, "House Allowance" ends up in "Employee Pensions and Benefits", is that how I read this?
A (Read) That's, based on what the table is showing, correct.
Q Okay. But that's what it's intended to represent?
A (Read) Correct.
Q Okay. Anybody on the panel know what "House Allowance" is?
A (Dawes) I'm assuming it's some sort of benefit that certain people get. Certainly, Erin and I do not get that benefit. But I'm not familiar with anyone in New Hampshire that has a housing allowance. But it's just from -- it's an example of showing how get from the natural account to the regulatory account. That may exist in other jurisdictions or in Corporate, I'm not sure.
Q Okay. So, Slide 12 talks about adjustments that were made to the 2022 balances for reporting

adjustments. This was -- this was to account for the mismapping that occurred, despite the testing that took place anyway, right? This is to describe what actually happened?

A (O'Brien) I think I can best answer that question.

So, Luisa explained the FERC derivation tables in SAP. Those are automatically pulled, however, in some cases, they can be overwritten through a manual journal entry.

So, if I take us back to January of 2023, we closed our books and records, went through our normal year-end closing process. Much of that work is around the natural accounts, which represents our U.S. GAAP reporting for our parent company, which is in public company reporting. And, following the completion of that work, we moved to the regulatory account analysis for the preparation of the FERC Form 1 and the revenue requirement.

In preparing that information, we identified that net income from a regulatory account perspective was very different from a U.S. GAAP perspective, which we wouldn't expect to see. This was new to us in the new system. We explained that the -- in the legacy system, we had one GL account. There was one account, and that determined both our U.S. GAAP and regulatory reporting results. In the new system, there are two accounts; our natural account, representing our U.S. GAAP results, and the regulatory account, representing the FERC accounts and our regulatory reporting.

So, when we began to prepare our FERC Form 1, and identified that net income was different between the U.S. GAAP and the regulatory results, we quickly identified that that didn't make sense. We don't expect to have GAAP to FERC differences in our results. That's what led us to complete this detailed review. And the timing of that is what drove it not being included in our 2022 SAP general ledger, because of when it was performed, we weren't able to reopen the books at that time.

So, this slide is discussing that detailed analysis that was done to identify those corrections. All of the transactions were in the system. So, it's all of the same SAP transactions that were in our results. It was an issue of geography and understanding where those transactions should have been recorded, to ensure that the regulatory results were accurate.

Q So, we heard this at the January 4th hearing also, about geography. You would agree that an entry, a transaction, if it doesn't end up in the right account, represents a mistake or a problem correct? I mean, if a transaction ends up in an income statement account, when it was supposed to go to a balance sheet account, there's really no comfort in the fact that the transaction was there, if it ended up in the wrong place, right? Or, am I missing something?

A (O'Brien) In these cases, it was in the correct location, from a U.S. GAAP reporting, and that's where our analysis began. Now, we are smarter in the system, and aware that we need to be doing this regulatory account analysis in conjunction with the GAAP analysis. That was not something that we were aware of in January of last year.

Q Okay. Well, that didn't really answer my question, though. If you've got a transaction on your books, but it ends up in the wrong account, that's a problem that needs to be dealt with. Would you agree with that?

A (O'Brien) Yes, which is what we did.

MR. DEXTER: Okay. All right. Thanks. That's all the questions I have.

CHAIRMAN GOLDNER: Okay. Given the late hour, let's take a very brief break, returning at 3:20, with the Office of the Consumer Advocate. Off the record.

(Recess taken at 3:11 p.m., and the hearing reconvened at 3:24 p.m.)

CHAIRMAN GOLDNER: Okay. We'll go back on the record, and resume with Attorney Kreis, and the OCA.

MR. KREIS: Thank you, Mr. Chairman.

Good afternoon, Liberty witnesses. I don't plan on taking up too much of your time, because I want to throw you to the wolves up on the Bench as quickly as I possibly can. But I do have a few questions.

BY MR. KREIS:

Q My first question is, as among the three of you, which of you is the highest ranking person in Liberty Utilities?

A (Dawes) Well, --
A (Read) I think Peter is --
A (Dawes) -- I'm not sure.
A (Read) -- probably equivalent.
A (Dawes) Yes, I think so.
A (Read) We both have "Vice President" titles. So, and Peter is in the region, and I'm in the Corporate Head Office. But --
A (Dawes) You know, we both report to Vice Presidents or higher in Corporate.
Q Okay. I think, because I really enjoy the Canadian accent, I'm going to ask my questions of Ms. Read. And, hopefully, she'll be able to answer them.
I was taking a breeze through the 2022 Annual Report of Algonquin Power & Utilities Corporation, which, of course, is the ultimate parent company of the utility that is under examination here today.
And I noticed, on Page 63 of that Annual Report, which, by the way, is the latest one that has been published, since I assume the 2023 Annual Report is not ready, it being only a few days after the end of 2023. And, so, there's

a section there, on Page 63, that is titled "Technology Infrastructure Implementation Risk". And I'm going to read you a sentence from that section of the Algonquin Power & Utilities Corp. Annual Report.

It says "AQN", which is the abbreviation they use for "Algonquin", "and certain of its subsidiaries are in the process of updating their technology infrastructure systems through the implementation of an integrated customer solution platform, which is expected to include customer billing, enterprise resource planning systems, and asset management systems."

So, my question for Ms. Read is, is what they're talking about there the same thing that you've been talking about here, that I think you've called "Customer First"?

A (Read) That is correct.

Q Indeed. So, the next sentence of the Annual Report says "The implementation of these systems is being managed by a dedicated team." And I realize you didn't write the Annual Report, presumably, and might not have even read it, but would it be fair for me to infer that, by "dedicated team", they're not necessarily talking about the degree of dedication to the Company of that team, but the fact that that team has been assembled and specifically assigned to focus on that project? That's what they mean by "dedicated", right?

A (Read) That is correct.

Q Yes. And, so, the next sentence says "Following successful pilot implementations, deployment began in 2022, and is expected to occur in a phased approach across the enterprise through 2024."

Now, that sentence is from the Annual Report for 2022, and some time has gone by. Is that still a true statement, about the parent company's intention as to the whole project, with reference to the timeline in particular?

A (Read) That is correct. The Customer First system implementations that have been done at Algonquin, the parent company, is across six, we call them "releases". Our last release is expected to go live in February, this year, in 2024.

Q So, in that continuum, starting with the pilot program and ending with whenever this project is over, where does Granite State Electric's fall? Like, was it the first operating subsidiary that you did this with, or was it the last one, or is it somewhere in the middle?

A (Read) I'd probably say it's somewhere in the middle. Because we had New Hampshire was our first one, then we had Corporate, Georgia, and St. Lawrence Gas were our second one.

I believe New Hampshire was our third release that we worked on.

A (Dawes) Sorry, just to clarify. Massachusetts was the first.

A (Read) Massachusetts, right.

A (Dawes) You said "New Hampshire".

A (Read) I'm sorry.

Q Yes.

A (Read) Massachusetts. Thank you.

Q Thank you. So, you started with Massachusetts, and then Granite State Electric, which is our affiliate here, was the third.

The next sentence from the Annual Report says "The implement" -- well, let me, before I go there. Is Granite State Electric the only operating subsidiary that's part of this project that is doing a rate case at the same time?

A (Dawes) That would not be yours to answer, Luisa.

A (Read) Yes. I'm sorry. I would defer to others on the Liberty team to answer that question.

Q Does anybody on the panel know the answer?

A (Dawes) So, we're obviously in the midst of the EnergyNorth rate case, --

Q Right.

A (Dawes) -- as you well know. We're in the late stages of a rate case for New York Water. They went live with SAP in November of '22. But they went from SAP to SAP. So, a little easier implementation. They're going from an older legacy system.

Gas New Brunswick just finalized a rate case, and they're filing another one in the coming weeks, I believe. A little different regulatory structure in New Brunswick.

In Georgia, there's an annual, it's called the "GRAM" mechanism, the "Georgia Rates Adjustment Mechanism". It's kind of a very prescriptive rate filing. But they do that annually. And we just reached settlement in their most recent GRAM filing.

Q So, you have various rate proceedings ongoing.

A (Dawes) Yes, we do.

Q But it sounds like, and please correct me if I'm wrong, the New Hampshire affiliates, meaning Granite State Electric and -- I always forget the name of the gas affiliate.

A (Dawes) EnergyNorth.

Q EnergyNorth, thank you. Are those the only two affiliates that have filed rate cases in which the test year is also the year that SAP was implemented?

A (Dawes) No. So, New York Water would have been a test year 2022, with two months in new system, ten months in legacy. Georgia is a little different, like I said. I mean, it's somewhat of a forward-looking test year, but some of it was SAP, some of it not. And New Brunswick is a completely forward-looking test year, with much less reliance on "regulatory" accounts than we have in other companies.

Q So, that sort of anticipates my next question, which I guess, Mr. Dawes, you can answer, since you seem to be the most knowledgable about this stuff.

Did those rate cases -- have those rate cases experienced the same degree of difficulties arising out of the transition into the SAP system that our rate case -- that at least this rate case here, in New Hampshire, has experienced?

A (Dawes) No. But it doesn't mean they were necessarily without some challenges. But certainly not the extent of the adjustments that we made here.

I think Georgia had some challenges, because it's very prescriptive what the regulator wants. They want to see things a certain way. So, to get the old accounts to the new accounts, it took a lot of work. So, that was challenging. We were able to overcome it, but it took a lot of work.

And New York Water did have some challenges with some of the regulatory accounting. But I think we're getting pretty close to finalizing that case. So, nothing significant that would impact the outcome of that case.

Q So, do you have a theory about why it is that we had so much trouble here, in New Hampshire, when those affiliates, the process went more smoothly, apparently?

A (Dawes) Yes. So, I think one of the issues, and Erin can certainly chime in, is we have a service company in New Hampshire, which we don't have a service company anywhere else. So, transactions come into the service company, they then get what we call "settled" or "pushed down" to the operating utilities.

So, some of the issues that we ran into were the setup of the service company settlement rules, how the costs then got pushed down to the regulatory accounts. We didn't have that issue with our other utilities, because they don't have the service company.

Q Moving on to the next sentence, I guess I'll stick with Mr. Dawes, since he seems to be on a roll. The next sentence of the Annual Report that I was reading from before says "The implementation of such technology systems will require the investment of significant financial and human resources." And, then, the next sentence after that says "Disruptions, delays, or deficiencies in the design, implementation, or operation of these technology systems, or integration of these systems with other existing information technology or operations technology could: Adversely affect the Company's operations, including its ability to monitor its business, pay its suppliers, bill its customers, and report financial information accurately on a timely basis; lead to higher than expected costs; lead to increased regulatory scrutiny or adverse regulatory consequences; or result in the failure to achieve the expected benefits."

So, my question about that sentence is, basically, and I apologize if it comes across as snarky, but would it be fair for me to infer that -- that the parent company, the ultimate parent company here, Algonquin Power & Utilities Corporation, warned its shareholders of exactly the kind of regrettable situation that we're experiencing here as a real possibility?

A (Dawes) So, I, like Ms. Read, was not part of preparing the -- I'm assuming this is part of the MD&A for Algonquin. I'm assuming that's the part of the document. Which has a lot of requirements from the SEC and regulators to discuss what your risks are.

Q Yes.

A (Dawes) So, I'm not sure --

Q Or, at least I made the same assumption that you did.

A (Dawes) Yes. So, I'm not sure who prepared that or the thinking that went into it. I know companies, as a general rule, have pretty lengthy sections on risks. Whether they're probable of happening or not is a different story. But I think companies are generally -- are generally pretty conservative about the risks that they lay out in their MD&As. And I have a -- I used to prepare the MD&A for Bangor Hydroelectric Company for years, haven't done that for probably 20 plus years.

Erin might have a little more recent experience in reviewing MD&As. But that's the best I think I can give you.

Q Sure. I guess what I really want to ascertain, though, is it fair to say that Liberty Utilities was well aware that things could go awry in exactly the way things have gone awry here?

A (Dawes) Well, I think they were raising the potential risk. I don't believe -- I mean, I don't believe Algonquin thinks what's happening here or the mapping issues that we've had certainly gives rise to something of significance for disclosure in the financial statements. I think this is a general risk statement that everyone makes in their financial statements for public filings.

Q Okay. I think this might be my last question. And, actually, some combination of all of you could answer this question, or one of you could, it doesn't really matter. And I apologize if this comes across as uninformed. But I don't usually wallow in the books and records of the utilities, and I don't usually find myself worrying about whether your FERC Form 1 aligns with your natural accounting, or your unnatural accounting, it just is something I don't usually deal with.

And, so, as we think about how to go forward here, I guess the question becomes, to what extent can we, in the future, expect that there will still be I guess I would call them "fixes" to the record, the financial records of last -- of the test year 2022, and the ensuing year, 2023, that we can still expect Liberty Utilities to be making in 2024, or even further into the future?

A (O'Brien) So, as far as, if I understand the question correctly, fixes you can expect going forward, I would say that those existed in our legacy system as well. There is always a new, for example, the Work Breakdown Structure, there's always new WBSs being set up. And we work diligently to ensure that those are done correctly, and we have checks in place, and have learned a lot about the system, to ensure that, if something is set up incorrectly, then that's identified and corrected.

I will say that the root causes for what we have identified in the system, they have been corrected. Those are corrected as we identify them.

And, similar with, for example, the incorrect WBS setup, that would be corrected in the system as soon as it's identified.

A (Dawes) And I would just quickly add on. I think, in answering your question, I don't -- I don't expect there to be any adjustments in 2024 that relate back to 2022 or beyond.

And just quickly, on the WBS, so, we're actually setting up a more centralized process across the whole organization for WBS creation and validation, to make sure that they're set up appropriately. So, I mean, that's good controls that we're putting in place going forward, to make sure we don't have similar issues in the future.

Q Okay. But here's what I don't get. I mean, I'm used to looking at annual reports of publicly traded companies. You know, they will close their books on the last day of 2022. They will put out an audited financial statement in April of 2023. And that's it. That's all chiseled into the entablature of the Corporate headquarters, and it can't be changed.

But it sounds like here the paradigm that you're operating under is that you reserve the right to update the financial records for regulatory purposes in perpetuity. What am --

like, how can that be? What am I not understanding?

A (Dawes) So, first, Don, I mean, obviously, there's a difference between the two. So, from a public reporting standpoint, you can have significant efforts going into an annual report, footnote disclosures, MD&As, and performance. So, I mean, you have to get the books closed fairly quickly so you can spend all that time getting that prepared.

The regulatory reporting is different. It's not uncommon that we make updates to our FERC Form 1, if we find something when we file it in the future. I mean, you wouldn't do that with an annual report to shareholders. But it's not uncommon that you might something in the FERC Form 1 that you need to update, because it's a pretty significant report, just beyond the regular financials, I mean, there's hundreds of pages in your FERC Form 1.

But we're only making -- we're making updates at the beginning of this year, to make sure our FERC Form 1 for 2022 -- sorry, last year, we're in 2024 now, in early 2023, to make sure the 2022 report was correct. Which, I mean, that's something we had to do. We couldn't file our FERC Form 1 that had the incorrect information in it. So, that's why we made those adjustments for the filing.

And our FERC Form 1 for this year, I mean, we shouldn't have the same issue going forward.

Q So, I guess -- this is my last question, I promise. So, at what point does the regulatory accounting become sufficiently reliable, so that the three learned experts sitting up there on the Bench can actually decide what the just and reasonable rates for this Company are? Like, at what point can they just say "All right, we're going to rely on the books and records we have in front of us in this record and decide what the just and reasonable rates are"?

A (Dawes) So, we certainly made a revenue requirement update in November, that included adjustments that came out of the audit process, through discovery, I can't recall if there was anything else that was a part of that. And we know that we have a small impact on the revenue requirement from the final adjustment work that we just finalized for the 2022 year-end numbers.

So, I would say, what was in that November Update filing, plus the small revenue requirement update. I mean, that's it. Those are the final numbers for 2022, adjusted.

Q Okay. Unless your two colleagues want to embellish that answer at all?

A *[Witness O'Brien indicating in the negative.]*

MR. KREIS: Just want to make sure that they didn't want to.

I think those are all the questions I have. And, now, I can turn you over to the folks up on the Bench. Or, actually, I think Dartmouth gets to ask you a few questions first.

CHAIRMAN GOLDNER: Yes. We can move at this time to Attorney Getz, any questions?

MR. GETZ: No questions, Mr. Chairman.

CHAIRMAN GOLDNER: All right. Thank you.

We'll turn now to Commissioner Simpson.

BY CMSR. SIMPSON:

Q So, the first question I have is quite general. Can you describe the driving factors that led to the Company filing this case in 2023?

A (Dawes) Yes. So, I would say, and there where a number of factors. So, we are on a three-year sort of timeline for filing new revenue requirements. I think there's a stay-out provision in New Hampshire, you can't file any sooner. We certainly couldn't go another year, given the significance of financial investments, whether it was in Customer First or, say, Tuscan Village. We wanted to do some additional things from a veg. management standpoint. The timing seemed appropriate to use a 2022 test year. We knew that we had gone live with SAP towards the tail end of the test year, so, nine months old system, three months SAP. And we had a good eight months post SAP to feel comfortable with the numbers that went into the filing.

Q And I asked the Department, and I'll ask you, could you comment on the financial health of Granite State Electric, and Algonquin Power & Utilities Corp., in general?

A (Dawes) Yes. So, I mean, I think the comment that came previously was -- I mean, it was more directed towards the impact of the mapping issues and things like that.

So, I'm not aware of any financial concerns, from a health standpoint, of the parent company. I think we just made a large debt offering. We're paying a dividend. We're earning money. I don't think there are financial health concerns. I'm not aware of any. Excuse me.

In Granite State Electric, we're meeting our obligations to our debt holders. We're paying our employees. We're billing and collecting money from customers.

And I think our financial health is sound across Algonquin.

Q And you have liquidity?

A (Dawes) We do.

Q Okay. So, we talked about the Audit Report at length this morning. And there were several issues that we went through. And I noted one, that was specifically Exhibit 8, Bates Page 152. When the DOE's Audit team identified some concerns, why didn't the Company follow up on all of those?

A (Dawes) Which audit issue is that? I'm sorry.

Q It's on Bates Page 152. So, I will get there.
A (Dawes) Sorry. I've got the actual Final Audit Report, as opposed to the Bates.
MS. RALSTON: It's the same page, Peter.
WITNESS DAWES: Is it?
MS. RALSTON: Yes. Page 152.
WITNESS DAWES: Just one second, I'll get there. It must be Audit Issue 1.
BY CMSR. SIMPSON:
Q So, this was "Accumulated Depreciation and Cost of Removal", "Audit Issue Number 2".
A (Dawes) Oh. Yes.
Q Just one example. So, Audit -- I'll read the comment: "Audit concurs, and requests that copies of any adjusting journal entries be provided to Audit within 30 days of this Final report." And that report is dated, I believe, October of '23.
A (Dawes) I'm there.
Q Okay. Do you need me to restate the question?
A (Dawes) I'm sorry. Yes, please.
Q Okay.
A (Dawes) I must not have heard it.

Q So, there was a audit issue identified, the Department requested an adjustment and a response from the Company. Why didn't the Company respond?

A (Dawes) So, I believe -- so, two pieces to it. I believe we did update the revenue requirement. And I'm not certain why we wouldn't have provided the journal entry. I would have to talk to our Plant Accounting team to find out if that adjustment was made, and then provide that. So, that was an oversight.

Q But you're not aware of a back-and-forth between the Company and the Audit team following this report?

A (Dawes) I'm not aware of anything. Erin, are you?

A (O'Brien) No.

Q Okay. With respect to SAP, could you describe the process that the Company, and perhaps Algonquin Power & Utilities Corp., employed to select SAP?

A (Read) This is going back a few years, because the Customer First Program started about four years ago. The Company made a decision that its current infrastructure and systems that we were on, we were on a collection of different systems, and not just New Hampshire utilities that we have, we have utilities across the U.S., they're on three different financial systems, ERP systems, Great Plains, JD Edwards, PeopleSoft. We also had --

[Court reporter interruption.]

WITNESS READ: Oh, sorry. Sorry. I apologies. I'll go slower.

CONTINUED BY THE WITNESS:

A (Read) We're on three different -- we were on three different financial systems. We're on two different customer information systems and billing systems. We had three different Chart of Accounts. It was very difficult to get information across all of these companies to be able to report on it. Our systems were old. They were costly to maintain, and not fully integrated between our finance system, our customer information system, and our operation system. And we were looking to provide better customer experience for our customers, and that's also our utility customers, as well as our

internal customers, which are our employees.
BY CMSR. SIMPSON:
Q So, I'm looking at the Audit Report, which is Exhibit 8. And there's a summary of allocation for Liberty Utilities. If you look at Bates Page 030, it's Page 4 of the report. There are affiliates listed of Liberty Utilities.
And I'll give you a moment, if you can pull that up.
A (Read) I don't have a computer in front of me. So, --
Q Okay.
MR. SHEEHAN: If I may?
BY CMSR. SIMPSON:
Q You don't have the Audit Report?
A (Read) Not in front of me.
Q Okay. That's fine. Take your time.
MS. RALSTON: Could you repeat the page number please?
CMSR. SIMPSON: It's Bates Page 030 of Exhibit 8, which is Audit Page 4, 4 and 5.
[Atty. Sheehan providing his laptop to the witness panel for document view.]
MR. SHEEHAN: Bates Page?

CMSR. SIMPSON: Thirty.

CHAIRMAN GOLDNER: Thirty, in the lower right.

WITNESS READ: I'm there.

BY CMSR. SIMPSON:

Q So, maybe you could just describe the network of Algonquin companies? I see "Liberty Water (Arizona)", "Liberty Water (Texas)". The two New Hampshire affiliates are bolded. There are some other companies here.

Could you describe these, just very briefly, and let us know which of these companies also transitioned to the SAP platform?

A (Read) All of them would have transitioned. We currently have one release left to implement SAP, and that's in our Empire electric and gas utilities.

Q Okay.

A (Read) As well as our Missouri water utility in our Central Region, that are still operating on their legacy system.

Q Okay. And, just out of curiosity, what is "Woodson Hensley"?

A (Read) I believe it's a water utility.

Q It's a very small portion of your portfolio. And "Tinker Transmission", do you know?

A (Dawes) Yes. They're a small -- they're a small electric transmission company just in Canada. So, our radial line coming out of Maine that serves, essentially, the town that's disconnected from the rest of the New Brunswick power grid.

Q Okay.

A (Dawes) They used to be part of Tinker Hydro, and we had to split them apart from a FERC standpoint. So, they're a stand-alone now.

Q Okay. Thank you. So, all of these affiliates are being charged *pro rata*, based on an allocation factor that presumably the Company develops for the costs associated with really any capital project, correct?

A (Read) Correct.

Q Okay.

A (Dawes) I don't know about "any capital project". It would have to be something that's attributable across the enterprise.

Q Okay. But SAP is one of those projects?

A (Dawes) Correct.

Q Okay. So, could you describe the management process that occurred from the review of possible options, the review of the various systems. I think you identified three that were in place from a legacy standpoint, the selection of SAP, working with SAP, and any other vendors, to develop a process to transition the Company over to SAP, the testing, the verification, the audit? Describe that process for us, if you would please, that led us to "go live"?

A (Read) Well, maybe your first part of your question is, there was a review done on which system Algonquin would implement across its utilities. We looked at two, SAP and Oracle. We did a deep review and workshops to go through all the different modules, the processes, and the decision was made to go with SAP.

We then went through an RFP process to find an implementation partner to work with us on the implementation.

Q Who was that?

A (Read) That was IBM, who had deep utility industry experience, as well as SAP. So, we worked with them. We also worked with KPMG to help with the design of our Chart of Accounts.

We also worked with other third party vendors and consultants on other softwares that integrate with SAP. Power Plan, as an example, which is our fixed asset subledger, we worked with them.

And, as part of, and maybe the second part of your question is "How did we, as an organization or a company, determine we were ready with the "go live"?" There was a lot of governance, project governance on the Customer First Program.

We have, as part of the "go live", we had to go through a business readiness checklist, and it was very detailed. Specific items and tasks that needed to be completed, to ensure we had the system, technology was ready, like, we designed all the processes, we completed all the testing, across the Customer First Program, and not just finance, on the customer side, as well as operations. We had to make sure all the end-users were tested. We had to make sure we had all the documentation on the processes, from a controls perspective, to make sure that we had all our controls in place, and those were tested.

The Business Readiness Committee, which

is leadership from across our utilities, have a vote to determine whether or not they are ready to go. And, with that recommendation of "go", that gets presented to our Executive SteerCo, which has our CFO, CEO, our IT lead as well, as well as representation from Customer First, to have the decision that we were ready to go, based on this detailed checklist of the items that were completed in the tasks, and we were comfortable with the decision. It was a thoughtful decision, because it was for Granite State, it happened in Quarter 4, but it was October. So, we felt that, with the work that was done, and the system to be ready and the business to be ready, we were -- the Company made a decision we were ready to go.

Q And you did not, I believe I heard earlier, that you did not run the Great Plains system in parallel to SAP. You made a full migration. You stopped operating SAP **[**Great Plains**?]**, presumably September of 2023, give or take. And, then, in October of 2023, no more operation of Great Plains, fully operating the Company within SAP?

A (Read) That is correct.

Q Okay.

A (Dawes) Is it okay if I just supplement a little bit?
Q Please.
A (Dawes) So, I know I was part of the Business Readiness, and had to vote. And, I mean, we all knew it was going to be challenging. Any time you put in something like an SAP, it's a very challenging system.
Q Sure.
A (Dawes) I think the thing that gave us additional comfort, that we haven't talked about, is something called "hypercare", which is, I mean, a significant level of support, is pretty much all-hands-on-deck from the IBM and Customer First team, to address any issues that come up after you go live. And I think we had that through the month of January, I think, for the New Hampshire companies.
So, they were instrumental in helping us through some of the challenges we had with the service company settlement issues, where things weren't coming down to the right regulatory accounts. They were instrumental in helping us with year-end, sort of taking care of some of

those regulatory account issues. As well as the significant efforts that went into getting the mapping correct for our FERC Form 1, and the most recent adjustments that we're going to be making on our books for 2023. So, I mean, a significant level of support from those teams.

Q So, FERC Form 1 is based off of your closed books from the prior year?

A (Dawes) Correct.

Q When do you close the books? For example, when will you close the 2023 books?

A (Dawes) Yes. So, we're being a little more strategic this year. So, we closed the books from a GAAP standpoint, because Corporate needs to get moving on their financials. We're still working through regulatory account reclassifications. And those will be pushed into the SAP books when those are completed, I think, in another week or so, if that.

So, last year, I don't think we were generally aware of this ability to make specific regulatory entries on the books after we closed. I think it was the sense, like, once Corporate closed, and they're working on financials, no more adjustments could be made.

Q So, Corporate, they're interested in closing GAAP, but the separate set of mapped regulatory books, there's a degree of flexibility in making adjustments therein?

A (Dawes) Right. Because there are -- there are additional periods within SAP, it doesn't end with period twelve. There's thirteen, fourteen, fifteen. So, we can put these reclass entries that are necessitated from some of these mapping things that we're correcting that we talked about into period thirteen. We'll have final books and records, general ledger that's correct, that should tie to the FERC Form 1.

Q So, the issues that were identified by the Department's Audit team, in your opinion, do those relate in total, or in part, to the regulatory accounts? Or do they also relate to the GAAP accounts?

A (Dawes) So, Erin could jump in. But I believe they're only looking at regulatory accounts.

A (O'Brien) Yes. That's my understanding as well.

Q Okay. And do you all have confidence in the data that originated in the Great Plains system?

A (O'Brien) Yes.
Q And do you have confidence in the translation of that data to the GAAP accounts within SAP?
A (O'Brien) Yes.
Q So, the adjustments that have been made related to the translation from the GAAP accounts to the regulatory accounts within SAP, correct?
A (O'Brien) I'm sorry. Can you repeat your question?
Q The corrections that have been discussed *ad nauseam* relate to the translation of data from the GAAP accounts to the regulatory accounts within SAP?
A (O'Brien) Yes. That's right.
Q I'm understanding that correctly?
A (O'Brien) Yes.
Q Okay. And was IBM your partner in developing the code base, if you will, related to that translation of GAAP to regulatory accounts?
A (Read) Yes, they were.
Q And they have done that for other utilities?
A (Read) I believe what is currently designed for Liberty, with the regulatory account, is custom to Liberty, because we do have multiple

regulatory bodies and jurisdictions, where we have utilities that need to follow a different Chart of Accounts, like for Gas, for Electric, NARUC Water and Sewer.

The tables that IBM developed and created for us for the regulatory account derivation is specific to Liberty.

Q Are there any Liberty affiliates that use the same regulatory accounting structure matrix that Granite State uses?

A (Read) All of them do, and Granite State is an electric, FERC Electric. So, we have currently three, including Granite State, two other electric utilities, one in California and one in Empire. California is live in SAP at this moment. Empire Electric will go live next month.

Q Is there anything to distinguish Granite State from those companies, in terms of your implementation of SAP?

A (Read) There would be no difference, in terms of the implementation. But there are probably specific requirements to the California regulation that may be a different way of recording certain transactions that need to hit a specific account that would be different than Granite State Electric.

I don't know, Peter, if you want to --

A (Dawes) No. I mean, beyond that, I would just say, so, I'm in contact all the time with my cohorts in the West Region, where Calpeco is, and in the Central Region, where Empire is. And we talk a lot about SAP, the challenges, lessons learned. So, I mean, I've certainly had a lot of discussions with them about things they should be aware of going in, to make sure that this -- these whole regulatory mapping things were squared away, and they've spent a lot of time getting their implementations. So, they were in a better place than we were when we went live in New Hampshire.

Q So, you may have answered this, but just so I understand. Out of those three electric operating companies, was Granite State the first to transfer to SAP?

A (Read) That's correct. Yes.

A (Dawes) Yes.

Q Okay. So, this is, in your view, you won't face the same problem in California and the Midwest states that you will here, because you've identified them here?

A (Read) That is correct.

Q Okay.

A (Dawes) Yes. Sorry. And Calpeco went live in Q4 of 2023. So, a year after we went live in New Hampshire.

Q How have you communicated with customers about this issue?

I'm not a customer of Granite State or EnergyNorth. So, I haven't seen anything. How have you communicated with your customers about this issue?

A (Dawes) Yes. I don't think we can answer that. We're not customer witnesses.

MS. RALSTON: I think that was probably something Ms. Preston could have answered. We would be happy to follow up, if it's of interest to you. But I don't think these are the right witnesses, unfortunately.

CMSR. SIMPSON: Okay.

BY CMSR. SIMPSON:

Q Are you aware of any customer communication? You can answer "no."

A (Dawes) Nothing specific. I'm sure that we did. But I'm not sure of anything specific that I could point to.

Q Okay. And you mentioned a unique element of Granite State living within a service company, and I wanted to better understand that, if you would?

A (Dawes) You can start.

A (O'Brien) So, Granite State, the New Hampshire companies were the first companies brought on to the SAP platform with a service company in place. So, what we have since identified is that some of the configuration in SAP allowed for costs to come into the service company to the correct regulatory account, but not follow down to the operating company level.

So, for example, when payroll taxes are recorded, they first come into the service company, before they're allocated to the gas and electric companies in New Hampshire. And they were appropriately classified to the 408 regulatory account at the service company level, but that designation didn't follow those costs down to the operating companies. It landed them

in this 999 clearing --
Q Catch-all.
A (O'Brien) -- regulatory account. Exactly. So, that has since been corrected for all charges flowing through the service company. But that was not something that we fully appreciated at this time last year.
Q So, you effectively had two regulatory mappings. You had your GAAP accounts, that were then mapped to a service company regulatory account, which, effectively, then need to be mapped to a Granite State Electric and an EnergyNorth account --
A (O'Brien) Correct.
Q -- regulatory account?
A (O'Brien) Yes. That's right.
Q Okay. And when did you identify that issue?
A (O'Brien) That was identified through this process and was corrected in our system in November of 2023. And we recorded a manual journal entry to correct for all charges prior to that time.
Q So, more than a year from "go live"?
A (O'Brien) I'd say it was about a year from "go live", when it was identified, and it took some

time to correct in the system. It goes through a testing process, and to ensure that all of the updates are done correctly.

Q Did that affect billing?

A (O'Brien) No. No.

Q So, how does -- how does the system tie to your billing system?

A (Read) It's all on SAP. So, our customer information system is a separate SAP module that integrates to SAP financials, with the financial ledger, in the natural accounts and the regulatory accounts.

Q Okay.

A (Dawes) So, the billing, all of the activity coming out of the customer information system are pushed over into the "general ledger", if you will, on an automatic basis, and it happens daily.

CMSR. SIMPSON: I'm hoping one of the attorneys could point me to an exhibit that had the Department's customer contact, with respect to rate class, calls that you received from customers?

MR. DEXTER: Yes, Commissioner. That

was in the Motion. And, then, the numbers were tweaked slightly, and should appear in a letter that I filed in the case shortly after the January 4th hearing. I'm not sure they were by rate class.

And, of course, I'm talking about contacts to the Department of Energy, not customer contacts to Liberty.

In the original Motion, it's on Bates Page 21.

CMSR. SIMPSON: Just a moment.

[Short pause.]

CMSR. SIMPSON: There was most definitely a table that had customer by rate class, in terms of calls, that the Department received. I just -- I had it up, but I can't find it now.

Is Ms. Noonan still here?

MR. DEXTER: If I can consult with Ms. Noonan for a minute, we might be able to track it down.

CMSR. SIMPSON: Thank you.

[Atty. Dexter and Dir. Noonan conferring.]

MR. DEXTER: So, this morning we were talking about a chart concerning bills that were delayed as a result of the SAP implementation. It talked about "684 customers", and that was broken down by month and by rate class.

CMSR. SIMPSON: Yes.

MR. DEXTER: So, now, see if I can remember where that was.

It was attached to the original Motion. I believe it's Attachment 15 to the original Motion. So, just give me a second.

[Short pause.]

MS. RALSTON: I referenced -- go ahead.

MR. DEXTER: I was going to say, it looks like it's Exhibit 8, Bates Page 240. And that has a "266" next to it.

CMSR. SIMPSON: That is the one. Thank you. This is a big record.

BY CMSR. SIMPSON:

Q And I expect to get a response that this isn't something that these witnesses could speak to. But are any of you familiar with this table and are you able to speak to it?

A (O'Brien) I'm sorry.

Q Okay.
A (Dawes) No.
A (O'Brien) I'm sorry, no.
A (Read) No.
MS. RALSTON: Yes. I would just say, this is again for Ms. Preston. We would be happy to make her available on another day.
CMSR. SIMPSON: Okay.
MS. RALSTON: If that would be helpful? I just wanted to put that out there.
CMSR. SIMPSON: Okay.
MS. RALSTON: This wasn't expected.
CMSR. SIMPSON: All right. I think that's all I have. Thank you.
CHAIRMAN GOLDNER: Thank you. We'll move now to Commissioner Chattopadhyay.
BY CMSR. CHATTOPADHYAY:
Q So, I'm going to go to Exhibit 5 first, and that was a record request. And, so, if you have it, are you ready with that?
A (O'Brien) Yes.
Q Okay. So, Number 5, I'm looking at the responses now. Number 5, Number 8, Number 9, Number 10, and I'm just trying to confirm I didn't miss

anything. So, those are the ones for which the impact on rate revenue requirement has not yet been included, correct?

A (O'Brien) That's correct.

Q Do you have a sense of what the impact would be, if you include those four additional adjustments?

A (O'Brien) I am not aware of the impact to the revenue requirement, no.

A (Dawes) Yes. So, if you take the December items, I mean, if you net them down to the impact on the income statement, so, the effect on earnings, it's about $167,000. So, the revenue requirement impact might be different, based upon how it's incorporated into the case, if it's labor, non-labor, the inflation rate or other escalators that are used.

But the raw adjustment itself is 167,000 of reduced expense, if you will.

Q And that has not been included yet?

A (Dawes) Correct.

Q I'm just trying to get a confirmation. Okay.

A (Dawes) Yes.

Q Have you unearthed or have you found anything additional that you noticed beyond January 4th yet?

So, I'm looking for, again, SAP issues that you have isolated or identified, after the hearing on the 4th of January?

A (O'Brien) No.

Q Okay. Do you have other SAP issues that are not listed here, these are the top ten, that are, let's say, between 11 and 20, that can also matter, in terms of what the revenue requirement would be? Or, is it the case that your number, which was $167,000, that includes everything?

A (O'Brien) That includes everything.

A (Dawes) So, everything identified on here as "December 2023".

Q So, everything identified in December. So, how many others are there that were identified in December that are not in this list?

A (O'Brien) I don't recall exactly how many there were. But the net impact was that $167,000. These shown here may go in opposite directions, they're not all presented in the same manner.

Q Okay. So, you don't know how many more SAP issues --

A (Dawes) Yes. We have --

Q -- popped up?
A (Dawes) I'm sorry. We have the details of what makes up the 167,000. We don't have it right here, but --
Q Okay.
A (Dawes) -- it's certainly something that we do have.
Q Okay. And I'll think about it. But let's continue.
So, I'm going to go back to the attestation issue that we were talking about. And I want to make sure I followed what was relayed.
A (Dawes) Uh-huh.
Q So, it doesn't matter whether you look at the Tab 11 or Tab 6, because, you know, so, let's stay with 11, because that's when the rate case was filed. And, if you go to, I can't tell what page number it is, but it's your attestation. And I'm just trying to understand, based on the questioning from Attorney Dexter, the attestation at one point says "the utility's books during the test year have been expressly noted", correct?
A (Dawes) Yes.

Q And this was signed on the 24th of April?

A (Dawes) Correct.

Q At that point, did you provide anything that expressly noted any changes in the manner of recording an item on the utility's books, "during the test year have been expressly noted"? And, so, I'm trying to get a confirmation. Did you do that or, based on what I heard, appeared that that happened after, like, and there was some back-and-forth that led you to get it done by October?

A (Dawes) So, I'm not -- I wasn't involved in what was filed in the revenue requirements. That would be Kristin Jardin and Daniel Dane.

So, what I was referring to is my comfort with the numbers in the FERC Form 1, plus the other adjustments that we identified, as being proper to include in the filing.

But I'm not generally aware with what they included in the filing. But my understanding since is that the adjustments were not called out specifically.

Q So, you agree that there weren't, they -- even though you understood that they were, they were

actually not expressly noted?
A (Dawes) Yes. They were included in the balances in the filing.
Q Okay.
A (Dawes) They weren't separately shown as an adjustment to the FERC Form 1 numbers.
Q All of the adjustments that are noted in Exhibit 5, and the ones that you mentioned you undertook and you actually flagged in December 2023, these are all about 2022 test year. Can you just confirm that all of these will be appropriately addressed for 2023 going forward?
A (O'Brien) Yes. They will.
Q Is it already taken care of?
A (O'Brien) The majority have already been taken care of. And, as mentioned, we are making final adjustments to the regulatory accounts currently, to ensure that the figures are accurate at year-end 2023.
A (Dawes) So, in --
Q Go ahead.
A (Dawes) And, in fact, we haven't finished closing the books for 2023, from a regulatory account

standpoint.

Q Do you know how many SAP issues you're taking care of in finalizing the 2023 books?

A (O'Brien) We are undertaking one analysis currently, to ensure that the net income between U.S. GAAP and regulatory accounting agrees. It's an exercise done at each month-end period. And that's what's currently being done for the December period close.

Q So, there isn't any specific, like, you know, these are the issues that you're dealing with?

A (O'Brien) There is -- so, this is meant to capture, for example, if there was a WBS created, and utilized during the month, that may have been set up incorrectly, this analysis would capture that and correct for any such differences.

A (Dawes) So, this is finalizing the review of the so-called "999 clearing accounts", to make sure everything was cleared out of that appropriately to the correct regulatory account. I think we're just about done, and should have final adjustments in fairly soon, and be able to prepare our final year-end trial balance for 2023, from a regulatory account standpoint.

Q Can you -- so, as I understood, based on the testimony, you know, Granite State was the first electric company that you had to deal with with respect to SAP, you know, transition. Correct?

A (Dawes) Correct.

Q You have gas utilities. Of course, you have one here. How many gas utilities do you have, like, distribution utilities?

A (Dawes) So, in the East Region, for which I'm responsible, we have a gas utility in New Brunswick, one in New Hampshire, one in Massachusetts, one in New York, and one in Georgia.

Q And where was the SAP implemented first, as far as gas utilities are concerned?

A (Dawes) So, New England Gas, in Massachusetts, was first, in May of 2021. It was more of a pilot implementation. Then, we had two more in May of 2022. That would be the Georgia gas utility and St. Lawrence Gas, in Upstate New York. And, then, in October of 2022, we did Granite State Electric and EnergyNorth, and Gas New Brunswick. And, then, New York Water was in November of 2022. And Tinker Transmission was sprinkled in there somewhere. It's so small, I don't recall.

Q Can you provide some thoughts on whether you learned something from the implementation of SAP in the gas utilities that happened previous to what you did in New Hampshire? And that -- and does that help or did that create less of a problem than what you've seen in the electric company?

A (Dawes) Most definitely. I mean, Erin can probably talk to it better, since she was knee-deep in the New Hampshire implementations. But, I mean, because we had gone live with three other companies beforehand, I mean, we certainly knew a lot about how the system worked, the complexities around this regulatory account derivation, the settlements.

So, SAP is interesting, because it has assessment and settlement rules built in that the old system didn't have. So, we certainly understood how that worked, from the initial implementations.

So, clearly, we learned quite a bit going into the New Hampshire implementation, other than the impacts that this service company that we didn't have in the prior implementations.

CMSR. CHATTOPADHYAY: I have to share this. I'm in New Hampshire and I am a gas customer of Liberty Utilities. At one point, for whatever reason, I had to call. And being their customer for the last eight years or seven years, and they couldn't locate my account.

So, I'll stop there. So, I'm still concerned whether the SAP was implemented properly even there.

Thank you.

CHAIRMAN GOLDNER: All right. There's an ice storm coming at 9:00. We'll have you out of here before then.

[Laughter.]

WITNESS DAWES: Thank you.

CHAIRMAN GOLDNER: You're welcome. Even though, if there's an hour commute, we should be all right.

Just some clean-up questions.

BY CHAIRMAN GOLDNER:

Q The general ledger closing for the regulatory accounts, when will that be? You mentioned it

was not quite done yet.
A (O'Brien) It will be done in the coming week.
Q The coming week, okay. And is that done before, do you -- when you're doing your annual report, and all of your GAAP accounting, your standard reporting that you give to shareholders, and so forth, are your regulatory accounts closed before you complete your GAAP work? Or, is it -- it's not related, so you really keep those separate?
A (Dawes) The latter. So, we've already finished the GAAP closing of the books, and we're finishing up some of the regulatory entries. So, they're not too far apart, probably a week or two apart.
Q We used to close GAAP in like three days. Is that standard for you or is that not normal in this case?
A (Dawes) Five, five would be standard.
Q Five.
A (Dawes) We took a little extra time at year-end, just because we had some companies in the West Region that were new on SAP. And just making sure that we had the requisite time to make sure everything was in the system correctly.

Q Okay. So, five days for GAAP, and then call it "four weeks" for the regulatory piece?

A (Dawes) Yes. I mean, we close the books all at the same time. But we recognize at year-end, I mean, we need to get those, again, the "999s" cleared out. And we wanted to make sure that we got all the GAAP information cleared first, and spent the right time making sure the regulatory accounts were correct.

Certainly, under the -- well, considering what's been happening with our New Hampshire rate cases, it was incumbent that we get the regulatory accounts exactly right at year-end.

Q So, that 999 account, for year-end '22, so, when you're closing the books in January '23, did you zero out the 999 accounts at that time or was there still a balance left in those accounts?

A (Dawes) No, we did. But it got put into the 920 account. But, I think, as Erin mentioned, there were some amounts going in both directions within the account. And, so, 7,000 seemed like a pretty small number. But it was made up of much larger numbers going in both directions.

Q So, this $7,000 you talked about earlier was the net of everything or that was --

A (O'Brien) That was the net, yes.

Q Okay.

A (Dawes) Yes, at the end of 2022. At the end of 2023, the 999 will be zero.

Q Okay.

A (Dawes) Cleared out appropriately.

Q So, I'll just repeat that back. So, at the end of 2022, year-end 2022, so, closing the books January '23, the balance of 999 was 7,000, lots of ins and outs. But, for this year, it will be zero?

A (Dawes) Yes. It was zero last year. It's just how it was cleaned out differently last year, versus what we're doing this year.

Q So, then, I'm sorry. Walk me through the 7K thing again, what was that?

A (Dawes) So, there was a net 7,000 -- or a $7,000 balance sitting in the 999. It was moved to the 920 FERC account to zero out the 999 last year.

Q I see.

A (Dawes) Then, we subsequently determined that that was not the appropriate classification of

certain amounts within the 920 account.
Q Was the 920 account kind of where you dumped everything you didn't know about, or was that just one instance of dumping 999 into 920?
In other words, were there other accounts dumped into 920 that weren't right?
A (O'Brien) It was the one instance of the small dollars. We just -- we weren't aware at the time that it was -- yes, that it was made up of larger balances going in opposite directions.
A (Dawes) The 999 would just indicate there's a problem in the system, and needs to be resolved and put into the appropriate account. And I'd say we certainly know a lot more, subsequent to the end of 2022, as to how to treat the 999s.
Q How many line items was that that netted to the 7K, roughly? Ten? Twenty? One hundred? Six hundred?
A (O'Brien) I would say it's in the range of twenty.
Q Twenty?
A (O'Brien) Yes.
Q Okay.
A (O'Brien) It's not hundreds.

Q Okay. Very good. You may have answered this earlier, and I may have missed it. Were any of you personally involved with Ms. Moran in the DOE audit?

A (O'Brien) I was.

Q You were. Okay. So, you heard the Department of Energy represent earlier significant mapping issues, that's where we spent the bulk of our afternoon. And, then, I think you mentioned earlier that there were "sixteen accounting lines that made up those mapping issues." Did I -- is that the correct understanding?

A (O'Brien) Yes. That's right.

Q So, then, just help me understand here, as we close this hearing out. Why do we have one party that says "Hey, we've got huge issues. We cannot deal with this rate case. There's a lot of stuff that's really, you know, not right on the Company's books."

And we have the Company saying "Hey, it's only sixteen line items, not a big deal, 999 account with 7K, ten or twenty line items."

Tell me more about the Company's position, because I'm flummoxed by the difference in the perspective?

A (O'Brien) I think it's a difference in the presentation of the adjustments. We're able to identify the specific accounts, the specific regulatory accounts that were impacted by the adjustments, and that is the sixteen accounts that I mentioned.

I believe that the Audit Issue 1 breaks it down into just a different level of detail, and is, in looking at an adjustment, obviously, you'll have two sides to each transaction. And so, it's listing each those, and then breaking some of them down into further levels of detail, which is how you get to the difference between it's sixteen accounts, but can be presented up in more detailed views, which is what was done in Audit Issue 1.

Q Okay. Thank you -- whoops. Thank you.

Maybe you can give the Commission an answer to this question, which is, can you give us your top three lessons learned from this Granite State Electric SAP implementation? You're doing it all over again, you have an opportunity, what are your lessons learned? What would you say to us?

A (O'Brien) I think that the work that we're doing right now in our regulatory account analysis has been a learning, that was something that we didn't appreciate in the system in January of 2023. And our work there, and the timing of it, is important. It was a change for us, in having the Chart of Account structure in SAP. And, so, the timing of that regulatory analysis, and getting the adjustments recorded in SAP, is certainly a key item.

As well as the layout and presentation of any changes that we make to Audit Staff, and what they may need to see. I think what we learned throughout the audit, which we didn't -- we didn't appreciate until well into the audit, was the manner in which some of our reports present the accounts, and focused on the natural account, rather than the regulatory account. And, obviously, Audit Staff is focused on the regulatory accounts. And, so, just working to run reports differently and pull the information in a manner that makes it easiest for Audit Staff is a learning as well.

Q Okay.
A (Dawes) I would probably just add the service company. So, better testing and understanding of sort of the double costs coming in and then going down again. Ensuring that, when you've got a service company setup, that you're following it all the way through to the ultimate place on the books, that that's set up correctly.
Q And, I think, maybe said differently, you were surprised by the complexity. You thought you had a small electric utility in New Hampshire. We're going to go forward. We could have done this in some other areas, with gas and so forth, should be okay. And, then -- and you were surprised by the ultimate complexity?
A (Dawes) Well, I think we knew going in it was going to be challenging. I mean, SAP is a pretty significant implementation when you're putting in a system like that.

But I think we felt comfortable, knowing that we had been on the system for eight months, we had made the corrections to FERC Form 1. I think we felt comfortable, from a rate case filing standpoint, that we had the right

numbers in the filing at that time.
Q And I am puzzled by the timing. So, I think it was September of '22 when you implemented SAP, is that right? September/October?
A (O'Brien) October.
Q October. And, so, you closed the books. You're probably starting to notice some things aren't tying out. You've got some surprises in there. And you closed the books for year-end '22. You filed a rate case in I think it's May or something of 2023. You must have seen lots of issues at that time, but yet you went ahead and you filed the rate case.
So, I'm at least puzzled, in terms of why the Company went ahead with the filing of the rate case, when there were issues to tie out, there's lots of complexity. Why did the Company move forward with the rate case?
A (Dawes) Yes, I think -- I think that was a question earlier that I had answered. So, we, I mean, obviously, we had nine months old system, three months new system.
Q But my question, sir, is different. It's --
A (Dawes) I was going to take you through the

thought process to get there, though.

Q It's just when you filed in May, I don't understand why you filed the rate case in May, given everything you knew in May of '23?

A (Dawes) Yes. So, I think I said, so, when we updated the FERC Form 1 for the adjustments, we found the other adjustments, we incorporated in the filing. We felt that our numbers were fair and accurate at that point. So, we felt it was good to go.

And I think we did, I can't recall if we held off a little bit on the filing, I mean, we were finalizing the analysis, making sure we got the FERC Form 1 in the right place, and those other adjustments. But we felt it was the right time to file.

And it had been a number of months since we went live. And we knew that there were only three months in the new system. And we didn't feel that we could wait another year, given the significance of certain investments that we had made in infrastructure, the Salem investments in Tuscan Village, that we really couldn't wait another year.

Q Yes. Because I think the risk was high, right, because you have, if the rate case is dismissed, and rate case expenses, these kinds of things become shareholder expenses. And, so, the Company's decision to move forward was -- had some risk. So, you said you felt like you "couldn't wait", but there's risk in not waiting, too. So, I'm sure the Company balanced that risk at an executive level. But that's -- that's the line of questioning that I was aiming for. So, I appreciate your answer on that.

I think I'll just wrap up here with -- I just want to give any of the witnesses an opportunity to share with the Commission on how they would propose or you would propose moving forward?

We have the Department saying "We cannot move forward." I think the OCA has said the same thing. Dartmouth College has been silent. The Company is saying "To move forward."

Would you have any final thoughts for the Commission, in terms of the Company's position, based on the questioning from the parties and the Commission today, on how you would want to move forward?

A (Dawes) So, I'm certainly not a regulatory person or a lawyer. But I think there are still some open adjustments that need to be incorporated into the revenue requirement. I think Staff and other parties need to get comfortable with that all the adjustments that have been identified have been incorporated.

And, certainly, I'm a proponent, if people are amenable, to having a third party come in and just ensure that there's nothing else that hasn't been found, as far as mapping errors or anything like that.

Q Okay.

A (Dawes) And I know there were some commentary around "it could take up to a year." We've had discussions, and we feel comfortable it could be done within 90 days.

CHAIRMAN GOLDNER: Okay. Thank you. I just wanted to give you that last opportunity.

So, we can, at this point -- do my fellow Commissioners have any additional questions?

[Cmsr. Chattopadhyay and Cmsr. Simpson

indicating in the negative.]

CHAIRMAN GOLDNER: Let's move then to Company redirect.

MS. RALSTON: Thank you.

REDIRECT EXAMINATION

BY MS. RALSTON:

Q I'm just going to build on what you were just discussing, Mr. Dawes.

So, earlier, the OCA asked you a question along the lines of "at what point does the regulatory accounting become reliable, and when can the Commission rely on that?" And, so, my first question to you would be, as you sit here today, do you think the Commission can rely on what has been submitted by the Company?

A (Dawes) I think, once we submit the additional information for the 167,000 of adjustments, then, yes.

Q And I think this is what you just stated, but I'll just confirm. The Company has specifically proposed this third party review to make sure that everyone feels that way, that everyone is comfortable that we can move forward and have that assurance, is that true?

A (Dawes) Correct.

Q And the Company has already spoken to PwC to ensure that the review could occur during a 90-day period, is that accurate?

A (Dawes) Yes, we have. They have the requisite expertise in regulatory accounting, they certainly have the IT audit expertise, and they're independent. I mean, all of the big accounting firms are governed by independence.

And, I mean, I think I heard like "the chicken guarding the henhouse" or something like -- or, "the fox", sorry, "guarding the henhouse." I mean, that doesn't happen with relationships with parties like PwC. I mean, they're bound by such strict standards that it can't happen.

Q And, to ensure that everyone is comfortable with what you just described, the Company did anticipate making this third party available for Commission and party questions, is that true?

A (Dawes) Yes. I think the basis for which they would be providing something would be called -- it's called an "expert report", which would mean they could testify, they could be available for questions.

And we certainly have put it out there that we would be very comfortable talking through the scope of the work, to make sure that the folks were comfortable with what was being proposed to get comfortable.

Q Great. Okay. And, Ms. O'Brien, a few minutes ago you stated that one of the lessons you've learned during this process is that the same types of reports that the Company had been able to pull from the legacy system are no longer available. And, so, some time and effort was needed to create information in a format that made it easy for the Audit Division to review.

Is that an accurate synopsis of what you were stating?

A (O'Brien) Yes.

Q And did that need to try to get information into a format that the Audit Division could easily review, did that contribute to some of these delays we've heard referenced, did that take some extra time in this audit investigation?

A (O'Brien) They did.

Q Okay.

A (Dawes) And, Jessica, I would just say, I know there's been discussion around the allocations information. So, I mean, we spent time working on getting reports that can support a couple of the audit issues that were raised, one around the CapEx/OpEx Report and the Allocation Report. Things that weren't available in SAP originally, we've now been able to produce.

Q And a few minutes ago, Mr. Dawes, just to stay with you, Chair Goldner asked you about the timing of the filing, and said he was kind of perplexed, that the Company identified a number of adjustments, and then still moved forward with the filing. But, just to clarify, at the time the filing was made, the Company had made those adjustments, correct?

A (Dawes) Correct.

Q Okay. So, just to be totally clear, the lion's share of the adjustments, if you will, had been made before the filing, and so that was part of why the Company felt comfortable?

A (Dawes) Yes.

Q Okay. And, on a similar line of questioning, Ms. O'Brien, the December 2023 adjustment, that is all related to one issue, is that accurate?

A (O'Brien) Yes. It was done through one analysis, that's correct.

Q So, the reason that there are a number of lines in Exhibit 5, related to December 2023, is because I think you said approximately twenty accounts or line items were implicated, but it's all related to one issue with the system, correct?

A (O'Brien) That's correct.

Q Okay. And, then, I also just wanted to clarify, we've heard about some different mapping issues, and information ending up in the wrong account. And those issues are related largely to errors of configuration, not -- it's not an IT issue, it's when new transactions are being set up, is that a fair assessment?

A (O'Brien) Yes. That's right.

MS. RALSTON: That's all from the Company.

CHAIRMAN GOLDNER: Okay. Thank you.

And thank you to the Company witnesses. The Company witnesses are excused. You can stay seated where you are, if you like, or return to the hearing room.

We'll strike identification on Hearing Exhibits 4 through 9, and enter them into evidence.

We'll invite the parties to make closing statements on the record, beginning with the Department of Energy, followed by the OCA and other parties.

But, before we do that, we'll just take a quick five-minute break so the Commissioners can confer. And we'll go to close at ten of.

MR. DEXTER: Mr. Chairman, before we go off the record?

CHAIRMAN GOLDNER: Yes, sir.

MR. DEXTER: I was planning to close last as the moving party. I can do it first. But, since we went first, usually, the party that goes first, closes last.

CHAIRMAN GOLDNER: Thank you. Yes. Attorney Dexter, that would be fine.

MR. DEXTER: Okay.

CHAIRMAN GOLDNER: Off the record.

[Recess taken at 4:45 p.m, and the hearing reconvened at 4:55 p.m.]

CHAIRMAN GOLDNER: Okay. Before we close, just want to give everyone a heads-up before closing, that the Commission needs time to consider what we've heard today, review the transcript. So, what we're going to do is we're going to extend the stay until February 16. And we're going to cancel the prehearing conference that's currently scheduled for January 30th. So, procedurally, that is the plan.

And, if you're ready, and there's no other items, we can begin closing with the Company.

MS. RALSTON: Thank you.

First of all, thank you to the Commission for your attention today. We appreciate you allowing us to present witnesses and produce exhibits. This is, obviously, a Motion that has consequences to the Company. And, so, we really do appreciate your time.

We've heard a lot of testimony today from the Department of Energy, from the Company's witness panels, and a lot of different issues have been raised, including customer satisfaction. But the Commission should just remain focused on the one question that's really before it today, and that is "Whether the Department of Energy has met its burden and demonstrated that there is no basis to adjust the Company's rates?"

And nothing said today has changed the fact that the Commission has the authority to adjust the Company's rates, and that the Company has filed sufficient information to allow the Commission to determine a just and reasonable rate base and a just and reasonable rate of return, consistent with RSA 378:28.

What the Department of Energy has successfully demonstrated is something that has never been disputed by the Company. The Company identified a number of adjustments to its 2022 general ledger following the closing of the 2020 **[**2022**?]** books. The identification of those adjustments led to a FERC Form 1 and a revenue requirement schedule filed in this proceeding that do not identically match the 2022 general ledger. That is all true.

However, what is more important is that the Department of Energy has not supported its --

excuse me -- has failed to provide support for a determination that would support granting the Motion to Dismiss. The DOE hasn't demonstrated that the Company should not have made those adjustments in preparation of the FERC Form 1, should not have made those adjustments in preparation of the revenue requirement schedules. DOE has not demonstrated that the Company can't explain the variance between those -- the basis for those adjustments and the variance between the datasets. And they have not supported their conclusion that the financial data cannot be relied on.

RSA 378:28 specifically states "Nothing contained in this section shall preclude the commission from receiving and considering any evidence which may be pertinent and material to the determination of a just and reasonable rate base and a just and reasonable rate of return." There is no reason the Commission cannot review the adjustments, and the Company's explanations for those adjustments, as part of its determination of rates. There is no reason the Commission couldn't adopt the Company's proposal to continue the stay of this proceeding and engage the third party that the Company has proposed, at the Company's expense, to assess the overall reliability of the Company's regulatory filing and the Company's basis for asserting the underlying data is reliable.

Rate cases are complicated. Rate cases following a substantial system conversion add to that complexity. But the solution to this complexity is not to delay the Company's request to adjust rates. Delaying the rate case, by dismissing it, would mean the Company doesn't recover the costs of its significant capital investments. Delaying the rate case means that important policy issues, like battery storage and rate design, would go unaddressed.

We've heard a lot of retrospection and questions about why the Company didn't make different decisions based on information it didn't have at the time the decisions were made. The Company was asked why they filed the rate case that relies on a test year that included a system conversion. The question implies that a rate case relying on data from a system conversion is a wrong decision to make. But that ignores all the considerations that were taken into account, all the decisions the Company discussed today; checklists, testing, training, verification.

The Company provided testimony this morning -- this morning and afternoon about all of those factors that went into its decision. The Company also explained that all of those steps led to the adjustments that were made prior to the filing of this case. And that the Company can trace those adjustments from its 2022 ledger, to the FERC Form 1, and the revenue requirement schedules.

The Company has accounted for and explained each of the adjustments, consistent with its obligation to ensure its filings are accurate. This is an ongoing obligation that the Company has met by making these adjustments. Where the Company discovers a discrepancy, it identifies it and corrects it. This is a standard practice; it's not a basis for dismissing a filing.

The issue before the Commission is

really simple today: Has the Department of Energy met its burden? And the only way it could meet that burden is if they could demonstrate that the Commission could not set rates based on all of the information it has already received, and information it could receive, if this procedural schedule is reinstated, and continues with hearings and rebuttal testimony.

The Company recognizes that the complexity of this case has raised concerns by the Commission, because the Commission does look to the Department of Energy to investigate the filing, and here, the Department of Energy is saying it didn't have sufficient time to confirm the data supporting the Company's filings due to the variances that exist between the general ledger and the FERC Form 1. This is exactly why the Company offered the third party review that I discussed earlier. The Department of Energy should not be permitted to reject this proposal for a third party review, while simultaneously arguing that it didn't have time to perform its audit function and cannot confirm the reliability of the data.

Thank you for your time.

CHAIRMAN GOLDNER: Thank you. We'll turn now to the Office of the Consumer Advocate.

MR. KREIS: Thank you, Mr. Chairman, Commissioners.

I would like to thank everybody who participated in today's hearing. I enjoyed the opportunity to interact with the Liberty witnesses in particular. And I appreciate the high quality of the presentations and the arguments that I heard today. And, of course, the questions from the Bench were highly astute. And I appreciate everybody indulging us trying to breathlessly keep pace with all of the stuff that you all are doing.

That said, I have to say that I remain convinced that the Commission should grant the Motion that my colleagues at the Department of Energy have made. And I would like to point out, respectfully -- or, I would like to respectfully disagree with the premise of the closing argument that you just heard from the utility.

Ms. Ralston told you that "it is the Department of Energy's burden to demonstrate that there is no basis to adjust the Company's rates." And she didn't cite any case law for that proposition. And I actually don't agree that the Department of Energy carries any burden here. This is a rate case. And it is the utility's burden to demonstrate that it is entitled to the rate increase that it is requesting.

So, all the Department of Energy is doing here is bringing to your attention the ineluctable reality that the Company, because of an unfortunate confluence of events, can't meet its burden based on the rate case that it has filed here.

Now, I find myself arguing fairly often about what appears to the OCA as a bunch of perpetually moving targets. I mean, in all kinds of dockets, utilities make filings at the PUC, file petitions, ask for new rates. And, really, what their initial filing turns out to be is just kind of an opening volley, and then, as the docket goes on, they make updates and corrections and changes. And what they end up ultimately presenting to you at the hearing is something that differs pretty substantially from the relief that they originally requested of you by way of their initial petition or request.

Well, I'm inured to that reality, I guess. It's probably part and parcel of a regulatory process that needs to be somewhat flexible. But there has to be a limit. And I think what we're facing here is something that exceeds the limit.

Now, I don't want to be overly clever, but the reason I read those excerpts to the Liberty witnesses of the Algonquin 2022 Annual Report, which was issued in March of 2023, is to make clear that this Company knew and understood, its upper management knew and understood, because they acknowledged in writing that they were undertaking a significant risk here by filing a rate case and undertaking other initiatives at the same time that it was rolling out major changes to the way the Company does its billing and keeps its books and records for regulatory purposes.

That's a risk the Company undertook, and the result is the situation that we are in here, in which this Company, if you grant what --

the relief that the Department of Energy is requesting, is going to take a substantial financial hit that is not going to make the management or the shareholders of this Company happy.

But I contend, as the ratepayer advocate in the room, that that is exactly the kind of business risk that utility management undertakes. And, to tell this utility that it can't suffer the consequences of the bad decisions it made, to undertake risks that it probably shouldn't have undertaken, is to indulge in exactly the kind of plenary indemnification, to quote Justice Souter, that the New Hampshire Supreme Court precluded in 1988, when it confronted another very dire utility situation, that had to do with a utility that became insolvent because it continued to double down on its investment in a nuclear power plant.

Now, this doesn't sink to that level by any means. But, in a way, it's the same old story, right? You know, utility management makes business decisions, sticks with them, doubles down on them, and now has to suffer the consequences.

So, I think it's unfair to ratepayers, who ultimately has to carry the -- who ultimately pay the Company back, in terms of both a return of and a return on their investment, and bear all the costs of rate cases, it's really unfair to impose all of this on customers.

We didn't undertake any risks. Our customers, our constituents are captive ratepayers of this Company. And it just isn't fair to do anything other than agree with the Department of Energy, which doesn't, I assume, make requests like this lightly. I've been around here since 1999, just like Ms. Moran, and I have never seen the PUC Staff or the Department of Energy, or the OCA, for that matter, make a request as drastic as this one. That's because we're in a dire situation that you should take very seriously. And, ultimately, at the end of the day, I think you really do need to grant the Department's Motion, and send everybody back to square one.

So, that's my closing statement.

CHAIRMAN GOLDNER: Thank you.

And, Mr. Dexter, in your closing, if you could address whose burden this is. Because, if it's not your burden, I need to let Attorney Ralston go again. So, please proceed.

Oh, I'm sorry. Commissioner Simpson is reminding me, Mr. Getz, that you may want to make a statement in closing?

MR. GETZ: Thank you, Mr. Chairman. But I have no closing on behalf of Dartmouth.

Thank you.

CHAIRMAN GOLDNER: Thank you. Thank you.

Attorney Dexter.

MR. DEXTER: Well, the burden of proof on a rate case is clearly on the utility. So, I don't know what else to say about that.

CHAIRMAN GOLDNER: Well, I think the question was, in the Motion to Dismiss, whose burden is it?

Because I think what you said before break was that "I'd like to go last", for that reason. And, then --

MR. DEXTER: Well, we are the moving party.

CHAIRMAN GOLDNER: Right.

MR. DEXTER: Whether the -- I don't think that shifts the burden of proving reasonable rates from the utility to the Department of Energy. The burden of proving reasonable rates is on the Company.

CHAIRMAN GOLDNER: Okay.

MR. DEXTER: Now, that said, if the Company wants to add something to what I say here, I don't have any problem with that.

CHAIRMAN GOLDNER: Okay. That would be helpful, because I understood Attorney Ralston to say that "It's very simple, has the Department met its burden of the Motion to Dismiss?" And, so, that's what I'm responding to.

Attorney Ralston, would you like to jump in?

MS. RALSTON: Yes. I mean, I would just clarify, I'm not suggesting the burden, with respect to the rate case, has shifted to the Department of Energy. I was specifically referring to the Motion to Dismiss.

And I think, unless I also misheard Attorney Dexter earlier incorrectly, he agrees that the burden is on the moving party. And that's what I was referring to.

CHAIRMAN GOLDNER: Okay. Attorney Kreis, Attorney Dexter, are we all in synchronicity here or --

MR. KREIS: We -- I am not in synchronicity with the position the Company just took, that's for sure.

I mean, again, what Ms. Ralston said to you at the beginning of her closing was "that it's the Department's burden to demonstrate there is no basis to adjust the Company's rates." That is basically telling the Department it has to prove a negative. That's not the way this works.

I mean, the whole idea of a "burden" doesn't really make any sense in the context of where we are now, right? I mean, the burden of going forward with evidence that proves its case, meaning its rate case, that belongs to the Company. I mean, I suppose you could say that "the Department has a burden of persuasion to carry here", in that they made a motion and, ultimately, they have to convince you that their arguments are sound. But that's different than saying that "this Department was obliged to come forward with evidence that demonstrates there is no basis to adjust the Company's rates." What there's no basis for is that proposition. I don't know of any cases, either of the Commission or of the New Hampshire Supreme Court, whose precedents are binding here, that says that.

CHAIRMAN GOLDNER: Okay. I'm going to give Attorney Ralston an opportunity to reply. And, then, as the moving party, I'll let Attorney Dexter go last. And, then, we'll wrap up the hearing.

Attorney Ralston, anything that you would like to say?

MS. RALSTON: I don't think there's really a lot else to say here. I mean, I was not -- again, I wasn't suggesting that the burden of proof for the case has shifted. It's, you know, the Department of Energy made a motion. They have to be able to support their Motion. My closing statement was suggesting their Motion has not demonstrated that there's a basis here to dismiss this case.

And I'm not going to get into

semantics, you know, with Attorney Kreis. But that is what I was stating. I wasn't trying to shift burdens. And I think that is sufficient for today.

CHAIRMAN GOLDNER: Okay. Thank you, Attorney Ralston.

We'll wrap things up today with Attorney Dexter.

MR. DEXTER: Well, thank you, Mr. Chairman and Commissioners. And I hope I am able to convince you that granting the Motion is the right resolution in this case.

I, too, want to thank the Commission for the time today, and for the attention to the -- to, first of all, granting this hearing, and then hanging in here for seven or eight hours of testimony.

I think what we've learned today, clearly, is that 2022 did not make a good test year. I'm not going to go through all the various adjustments, and I'm not going to quibble whether there were 200 adjustments or 20 adjustments. But I will point out, the Audit Report is very detailed and it's very clear. I urge you to read the Audit Report, especially Audit Issue Number 1, concerning the state of the 2022 books.

We've heard, on and on, that there were significant adjustments that had to be made to the 2022 books to get from closing of the books, to presentation of the rate case. That presented challenges. And the challenges were not aided in any way by Liberty Utilities in this case. Liberty Utilities did not acknowledge that they made these adjustments to the books before coming before you with the rate request. They certainly didn't highlight them, they didn't even acknowledge that they existed.

They are required to detail the differences in the attestation that we went over today, and they didn't do that. Their testimony that I read to you, from Witnesses Jardin and Dane, didn't even mention these accounting adjustments that needed to be made. So, frankly, if there's confusion in this case, it falls on the lap of Liberty Utilities.

Their witness today, who I believe is the Vice President of Accounting, tried to draw a distinction between whether or not the books and records were the FERC Form 1 or the Rate Filing. And the fact of the matter is, that there were differences between the books and records and the Rate Filing; they were not highlighted, as required. There were additional differences between the FERC Form 1 and the Rate Filing; they weren't highlighted. So, I don't know where that distinction was coming from. The fact of the matter is, the Company did not highlight these significant changes, and they actually submitted an attestation to the contrary. You can read that for yourself and make your own judgment.

Why have we moved for dismissal? From the beginning, we've moved for dismissal, rather than a repair, because of the significant problems with the 2022 books, as indicated in the Audit Report. And what we heard today -- well, first of all, you know, the notion that the Company has now offered to have a third party auditor come in and verify that the books in the rate cases are all lined up and everything has been accounted for, that's great. That should have happened before the case was filed.

It's not the Department's role to go through this exercise that we've been talking about for the last -- for today, and back on January 4th, to try to find these issues, highlight them, or have the Company find them in the course of an audit, and address them as we go along. This is supposed to be done before the case is filed. It's the Company's burden of proof to present a rate case that has this information.

The notion that I think I heard today from the Vice President of Accounting is that "you don't base a rate base" -- "you don't base a rate case on the books of the company, you base it on the FERC Form 1", makes absolutely no sense to me. Because the FERC Form 1 doesn't have any transactions, it just has balances. The general ledger of the company is essentially the diary of what happened to the company all through the test year. You can't look at balances that are included in a FERC Form 1 and decide whether anything is reasonable and prudent. You have a plant balance of a million dollars, it doesn't tell you what's in it. In order to know what's in it, you have to go to the general ledger. You have to look transaction-by-transaction to find out what's in -- what's in rate base, what's in payroll, what's in O&M.

You know, the notion that "you don't base the rate case on the general ledger" is just absurd. And I -- and I urge the Commission to recognize that and call the Company out for that statement.

The notion that "only 16 accounts were affected" is what we heard at the end of the day, equally absurd. Plant, that's one account, okay, O&M, payroll, benefits, maintenance of poles, veg. management, I could list 16 accounts that would take care of 90 percent of these revenues and expenses on the Company's books. To try to minimize this to say "Well, it was only 16 accounts that were affected", is absolutely absurd. And, again, the Company -- the Commission should call the Company out on that, and not brush away serious problems, you know, by looking at the absolute value of the offsetting adjustments, again, an absurd notion. If you've got a problem with an account that goes down, and then you've got a problem with another account where it goes up, and the two of them balance themselves out, to say "Well, that's not a problem, they balance themselves out", absolutely ridiculous. And, again, the Commission should call the Company out for that.

So, what's the Commission's role here? According to 378:28, it starts by saying, and that's the RSA on setting permanent rates: "So far as possible, the provisions of 378:27 shall be applied [to] the Commission in fixing and determining permanent rates, as well as temporary rates."

So, what does 327:7 -- 378:27, on temporary rates, says that the Commission can set rates designed "to yield not less than a reasonable return on the cost of the property of the utility used and useful in public service less accrued depreciation, as shown by the reports of the utility filed with the commission and the department of energy, unless there appears to be reasonable grounds for questioning the figures in such reports."

So, today, we heard from the Company

that "reports" is defined as the "FERC Form 1". I think that's a bit of a leap. There are a lot of reports filed with the Company -- filed by the Company with the Commission, including the rate case itself. I believe you could read that as a report. And I don't think that this is limited to the FERC Form 1.

The important clause in this statement is that you can set these rates "unless there appears to be reasonable grounds for questioning the figures in such reports." I urge the Commission to go back and look at Audit Issue Number 1; Audit Issue Number 12, involving payroll; Audit Issue Number 25, involving Corporate allocations; and Audit Issue Number 13, and I can't remember what Audit Issue Number 13 covered. Significant issues that I think you should look at. You should look at Exhibit 4; you should look at Exhibit 5. And you should ask yourself "Do I have any doubts, if I have reasonable grounds for questioning the figures that were put forth in the Company's rate case when these issues have been raised?"

So, in closing, we continue to

recommend dismissal as the appropriate remedy. Again, the offer for the third party offer would -- the offer for the third party offer should have been done by the Company before this case was filed. Had it been done, many of these issues might have been avoided. But that's not an appropriate remedy, as we sit here in January of 2024, to go back and try to look at 2022 books.

We heard from the Company's accountants today that the 2023 books are a significant improvement over the 2022 case, and that the mapping issues are largely behind them. So, it seems to us that, in order for the Commission to remove any of the reasonable grounds it has for questioning the figures in such report, you should require the Company to file a rate case based on a test year no earlier than 2021 -- I'm sorry, 2023.

Your questions to the Company about "why on earth would you file a rate case on the same year that you are implementing an accounting change to the significant degree that you did?", and with the excellent excerpts from the

Company's Annual Report that the OCA brought forth today, those questions are right on, they're spot on. And the answer is "that they shouldn't have."

And, for all of the reasons that we put forth today, and on January 4th, there is grounds, reasonable grounds, for questioning the figures that were presented to you. And it's our opinion that you should not set rates based on the 2022 books.

Thank you.

CHAIRMAN GOLDNER: Thank you, Attorney Dexter.

Is there anything else that we need to cover today?

[No verbal response.]

CHAIRMAN GOLDNER: Okay. You've got an hour and 40 minutes to vote, if you haven't yet, which I haven't. And the hearing is adjourned. Thank you.

(Whereupon the hearing was adjourned at 5:19 p.m.)

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 23-067
Distribution Service Rate Case

Department of Energy Audit Request

Date Request Received: 9/21/23 | Date of Response: 10/3/23
Request No: AR 35 | Respondent: Sue-Ellen Billeci

REQUEST:

As part of a standard audit procedure, we compare your SAP year-end account balances (represented below, summarized by Regulatory account number) to the F-16 annual report, and then to the filing revenue requirement schedules.

The first column is your SAP regulatory account number, second column is the 12/31/2022 balance, third column indicates where the dollars were verified to your F-16, then the last three columns compare the filing schedule and balance to the SAP. Clearly there are issues with almost every Operations and Maintenance account figures represented in the filing.

Please indicate precisely what the variances are and where they can be found in the filing schedules. Also indicate why the annual report appears to reflect the SAP, but the filing does not.

Docket No. DG 23-067 Request No. AR 35

	1,388,068.78	sum of these four accounts agrees with the		RR-EN-2-1	$ 1,461,346.00	$ (
	147,432.99	annual report O&M page 34 line one and		RR-EN-2-1	$ 34,408.00	$ 1
	228,889.75	page 51		RR-EN-2-1	$ 434,858.00	$ (2
	102,511.76			RR-EN-2-1	$ 257,313.00	$ (1
	(21,316,737.09)	ok to O&M page 35 account 804		RR-EN-2-1	$ 10,467,995.00	huge v
	19,348,136.26	ok to O&M page 35 account 804.1		RR-EN-2-1	8041 part of 8040?	$ (12,4
	(1,074,189.83)	these 2 sum to $105,879,815 which agrees with the		RR-EN-2-1		
	106,954,005.14	annual report O&M page 35 account 805 $105,879,815		RR-EN-2-1	$ 105,879,815.00	$
	7,481,472.49	ok to O&M page 35 account 808.1				
	(11,597,244.98)	ok to O&M page 35 account 808.2		RR-EN-2-1	$ (4,115,772.00)	$
	(2,472.23)	ok to O&M page 37 account 844.2			$ -	
	-			RR-EN-2-1	$ 27,195.00	$ (
	6,429.59	ok to O&M page 37 account 846.2		RR-EN-2-1	$ 7,036.00	$
	-	ok to O&M page 37 account 850		RR-EN-2-1	$ 306.00	$
	7,810.65	ok to O&M page 38 account 863		RR-EN-2-1	$ 8,386.00	$
	698,972.94	ok to O&M page 38 account 870		RR-EN-2-1	$ 526,329.00	$ 1
	318,576.87	ok to O&M page 38 account 871		RR-EN-2-1	$ 301,395.00	$
	4,268,785.88	ok to O&M page 38 account 874		RR-EN-2-1	$ 4,922,998.00	$ (6
	12,278.92	ok to O&M page 38 account 875		RR-EN-2-1	$ 52,551.00	$ (
	1,086,521.39	ok to O&M page 38 account 878		RR-EN-2-1	$ 1,268,364.00	$ (1
	476,715.00	ok to O&M page 38 account 879		RR-EN-2-1	$ 614,499.00	$ (1
	3,664,128.93	ok to O&M page 38 account 880		RR-EN-2-1	$ 1,378,633.00	$ 2,2
	20,428.73	ok to O&M page 38 account 881		RR-EN-2-1	$ 36,016.00	$ (
	-	ok to O&M page 38 account 885		RR-EN-2-1	$ 110,719.00	$ (1
	539,426.38	ok to O&M page 38 account 886		RR-EN-2-1	$ 262,296.00	$ 2
	1,641,219.54	ok to O&M page 38 account 887		RR-EN-2-1	$ 2,306,529.00	$ (6
	-	ok to O&M page 38 account 889		RR-EN-2-1	$ 2,487.00	$
	341,912.43	ok to O&M page 38 account 892		RR-EN-2-1	$ 559,259.00	$ (2
	260,450.06	ok to O&M page 38 account 893		RR-EN-2-1	$ 339,700.00	$ (
	258,656.19	ok to O&M page 38 account 894		RR-EN-2-1	$ 368,744.00	$ (1
	114,224.32	ok to O&M page 38 account 901		RR-EN-2-1	$ 149,424.00	$ (
	1,136,505.15	ok to O&M page 38 account 902		RR-EN-2-1	$ 453,911.00	$ 6
	2,203,345.33	ok to O&M page 38 account 903		RR-EN-2-1	$ 2,107,953.00	$
	1,153,435.45	ok to O&M page 38 account 904		RR-EN-2-1	$ 1,153,436.00	$
	44,994.27	ok to O&M page 38 account 905		RR-EN-2-1	$ 60,701.00	$ (
	92,246.97	ok to O&M page 39 account 909		RR-EN-2-1	$ 92,247.00	$
	268,555.38	ok to O&M page 39 account 912		RR-EN-2-1	$ 253,928.00	$
	0.00	ok to O&M page 39 account 913		RR-EN-2-1	$ 82,021.00	$ (
	59,058.91	ok to O&M page 39 account 916		RR-EN-2-1	$ 59,059.00	$
	15,957,477.35	ok to O&M page 39 account 920		RR-EN-2-1	$ 1,706,504.00	$ 14,2
	6,280,347.64	ok to O&M page 39 account 921		RR-EN-2-1	$ 6,406,776.00	$ (1
	(8,946,903.70)	ok to O&M page 39 account 922		RR-EN-2-1	$ (8,941,610.00)	$
	5,756,461.79	ok to O&M page 39 account 923		RR-EN-2-1	$ 5,855,336.00	$ (
	130,113.63	ok to O&M page 39 account 924		RR-EN-2-1	$ 130,114.00	$
	1,423,337.76	ok to O&M page 39 account 925		RR-EN-2-1	$ 1,423,852.00	$
	5,238,413.62	ok to O&M page 39 account 926		RR-EN-2-1	$ 7,240,313.00	$ (2,0
	1,090,204.02	ok to O&M page 39 account 928		RR-EN-2-1	$ 1,090,204.00	$
	(3,221,497.74)	ok to O&M page 39 account 930.2		RR-EN-2-1	$ (3,121,419.00)	$ (1
	119,834.59	ok to O&M page 39 account 931		RR-EN-2-1	$ 125,425.00	$
	0.00	ok to O&M page 39 account 932		RR-EN-2-1	$ 350,946.00	$ (3

RESPONSE:

See Attachment 23-067 AR 35.xlsx for details of the accounts that make up the amount reported in the Annual Report and identification of items not included which explains the differences noted.

7100	1,388,068.78	sum of these four accounts agrees with the
7170	147,432.99	annual report O&M page 34 line one and
7350	228,889.75	page 51
7420	102,511.76	
8040	(21,316,737.09)	ok to O&M page 35 account 804
8041	19,348,136.26	ok to O&M page 35 account 804.1
8050	(1,074,189.83)	these 2 sum to $105,879,815 which agrees with the
8051	106,954,005.14	annual report O&M page 35 account 805 $105,879,815
8081	7,481,472.49	ok to O&M page 35 account 808.1
8082	(11,597,244.98)	ok to O&M page 35 account 808.2
8440	(2,472.23)	ok to O&M page 37 account 844.2
8442	-	
8462	6,429.59	ok to O&M page 37 account 846.2
8500	-	ok to O&M page 37 account 850
8630	7,810.65	ok to O&M page 38 account 863
8700	698,972.94	ok to O&M page 38 account 870
8710	318,576.87	ok to O&M page 38 account 871
8740	4,268,785.88	ok to O&M page 38 account 874
8750	12,278.92	ok to O&M page 38 account 875
8780	1,086,521.39	ok to O&M page 38 account 878
8790	476,715.00	ok to O&M page 38 account 879
8800	3,664,128.93	ok to O&M page 38 account 880
8810	20,428.73	ok to O&M page 38 account 881
8850	-	ok to O&M page 38 account 885
8860	539,426.38	ok to O&M page 38 account 886
8870	1,641,219.54	ok to O&M page 38 account 887
8890	-	ok to O&M page 38 account 889
8920	341,912.43	ok to O&M page 38 account 892
8930	260,450.06	ok to O&M page 38 account 893
8940	258,656.19	ok to O&M page 38 account 894
9010	114,224.32	ok to O&M page 38 account 901
9020	1,136,505.15	ok to O&M page 38 account 902
9030	2,203,345.33	ok to O&M page 38 account 903
9040	1,153,435.45	ok to O&M page 38 account 904
9050	44,994.27	ok to O&M page 38 account 905
9090	92,246.97	ok to O&M page 39 account 909
9120	268,555.38	ok to O&M page 39 account 912
9130	0.00	ok to O&M page 39 account 913
9160	59,058.91	ok to O&M page 39 account 916
9200	15,957,477.35	ok to O&M page 39 account 920
9210	6,280,347.64	ok to O&M page 39 account 921
9220	(8,946,903.70)	ok to O&M page 39 account 922
9230	5,756,461.79	ok to O&M page 39 account 923
9240	130,113.63	ok to O&M page 39 account 924
9250	1,423,337.76	ok to O&M page 39 account 925
9260	5,238,413.62	ok to O&M page 39 account 926
9280	1,090,204.02	ok to O&M page 39 account 928

9302	(3,221,497.74)	ok to O&M page 39 account 930.2
9310	119,834.59	ok to O&M page 39 account 931
9320	0.00	ok to O&M page 39 account 932

RR-EN-2-1	$ 1,461,346.00	$ (73,277.22)	7100
RR-EN-2-1	$ 34,408.00	$ 113,024.99	
RR-EN-2-1	$ 434,858.00	$ (205,968.25)	
RR-EN-2-1	$ 257,313.00	$ (154,801.24)	
RR-EN-2-1	$ 10,467,995.00	huge variance	
RR-EN-2-1	8041 part of 8040?	$ (12,436,595.83)	
RR-EN-2-1			
RR-EN-2-1	$ 105,879,815.00	$ -	
RR-EN-2-1	$ (4,115,772.00)	$ (0.49)	
	$ -		
RR-EN-2-1	$ 27,195.00	$ (29,667.23)	
RR-EN-2-1	$ 7,036.00	$ (606.41)	
RR-EN-2-1	$ 306.00	$ (306.00)	
RR-EN-2-1	$ 8,386.00	$ (575.35)	
RR-EN-2-1	$ 526,329.00	$ 172,643.94	7170
RR-EN-2-1	$ 301,395.00	$ 17,181.87	
RR-EN-2-1	$ 4,922,998.00	$ (654,212.12)	
RR-EN-2-1	$ 52,551.00	$ (40,272.08)	
RR-EN-2-1	$ 1,268,364.00	$ (181,842.61)	
RR-EN-2-1	$ 614,499.00	$ (137,784.00)	
RR-EN-2-1	$ 1,378,633.00	$ 2,285,495.93	
RR-EN-2-1	$ 36,016.00	$ (15,587.27)	
RR-EN-2-1	$ 110,719.00	$ (110,719.00)	
RR-EN-2-1	$ 262,296.00	$ 277,130.38	
RR-EN-2-1	$ 2,306,529.00	$ (665,309.46)	
RR-EN-2-1	$ 2,487.00	$ (2,487.00)	
RR-EN-2-1	$ 559,259.00	$ (217,346.46)	
RR-EN-2-1	$ 339,700.00	$ (79,249.94)	
RR-EN-2-1	$ 368,744.00	$ (110,087.81)	
RR-EN-2-1	$ 149,424.00	$ (35,199.68)	
RR-EN-2-1	$ 453,911.00	$ 682,594.15	7350
RR-EN-2-1	$ 2,107,953.00	$ 95,392.33	
RR-EN-2-1	$ 1,153,436.00	$ -	
RR-EN-2-1	$ 60,701.00	$ (15,706.73)	
RR-EN-2-1	$ 92,247.00	$ (0.03)	
RR-EN-2-1	$ 253,928.00	$ 14,627.38	
RR-EN-2-1	$ 82,021.00	$ (82,021.00)	
RR-EN-2-1	$ 59,059.00	$ (0.09)	
RR-EN-2-1	$ 1,706,504.00	$ 14,250,973.35	
RR-EN-2-1	$ 6,406,776.00	$ (126,428.36)	
RR-EN-2-1	$ (8,941,610.00)	$ (5,293.70)	
RR-EN-2-1	$ 5,855,336.00	$ (98,874.21)	
RR-EN-2-1	$ 130,114.00	$ (0.37)	
RR-EN-2-1	$ 1,423,852.00	$ (514.24)	
RR-EN-2-1	$ 7,240,313.00	$ (2,001,899.38)	
RR-EN-2-1	$ 1,090,204.00	$ 0.02	

	RR-EN-2-1	$	(3,121,419.00)	$	(100,078.74)
	RR-EN-2-1	$	125,425.00	$	(5,590.41)
	RR-EN-2-1	$	350,946.00	$	(350,946.00)

7420

8040

8041

8050

8051

8081

8440/8442

8462

8500

8630

8700

8710

8740

8750

8780

8790

8800

8810

8850

8860

8870

8890

8920

8930

8940

9010

9020

9030

9040

9050

9090

9120

9130

9160

9200

9210

9220

9230

9240

9250

9260

9280
9302

9310

9320

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11710000	11710000	8,873.37
500010	Overtime	11710000	11710000	116.21
500300	Outside Svs	11710000	11710000	4,088.83
800000	Lbr Alloc	11710000	11710000	58,987.51
804000	WBS ST Lbr	11710000	11710000	(67,977.09)
804020	WBS ST Material	11710000	11710000	(1,211.73)
804030	WBS ST Services	11710000	11710000	(4,088.83)
505000	Other Operating Exp	11710000	11920000	-
505000	Other Operating Exp	11710000	11920000	9,386.25
500000	Salaries and Wages	11710000	11871000	802,519.66
505000	Other Operating Exp	11710000	11871000	213,743.94
500000	Salaries and Wages	11710000	11920000	363,630.66
				1,388,068.78

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500300	Outside Svs	11717000	11717000	11,539.65
502310	Facility Costs-Maint	11717000	11717000	482.88
505000	Other Operating Exp	11717000	11717000	6,956.00
800000	Lbr Alloc	11717000	11199999	146,846.47
800000	Lbr Alloc	11717000	11717000	714.43
800000	Lbr Alloc	11717000	11717000	14,715.13
802000	Settle Lbr	11717000	11717000	(127.91)
804000	WBS ST Lbr	11717000	11717000	(14,715.13)
804030	WBS ST Services	11717000	11717000	(11,539.65)
804040	WBS ST Other	11717000	11717000	(7,438.88)
505000	Other Operating Exp	11717000	11920000	-
802000	Settle Lbr	11717000	11717000	714.43
804000	WBS ST Lbr	11717000	11717000	(714.43)
				147,432.99

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
502300	Facility Costs	11735000	11735000	608.93
505000	Other Operating Exp	11735000	11735000	191.45
800000	Lbr Alloc	11735000	11735000	1,170.93
804000	WBS ST Lbr	11735000	11735000	(1,170.93)
804030	WBS ST Services	11735000	11735000	-
804040	WBS ST Other	11735000	11735000	(63,966.30)
804050	WBS ST Fleet	11735000	11735000	-
804085	WBS ST Travel	11735000	11735000	-
505000	Other Operating Exp	11735000	11920000	-
505000	Other Operating Exp	11735000	11920000	1,226.61
505000	Other Operating Exp	11735000	11871000	262,949.40
500000	Salaries and Wages	11735000	11735000	3,990.89
500010	Overtime	11735000	11735000	5,844.61
500100	Vacation & Other TO	11735000	11735000	428.41
500300	Outside Svs	11735000	11735000	424.20

505000	Other Operating Exp	11735000	11735000	1,395.31
800000	Lbr Alloc	11735000	11735000	118,951.19
804000	WBS ST Lbr	11735000	11735000	(128,786.69)
804020	WBS ST Material	11735000	11735000	(9,788.41)
804030	WBS ST Services	11735000	11735000	(424.20)
804040	WBS ST Other	11735000	11735000	(1,403.38)
804110	WBS ST OH Benefit	11735000	11735000	(428.41)
505000	Other Operating Exp	11735000	11920000	37,676.14
				228,889.75

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11742000	11742000	10,750.55
500010	Overtime	11742000	11742000	274.63
500100	Vacation & Other TO	11742000	11742000	261.00
500300	Outside Svs	11742000	11742000	30,006.56
502310	Facility Costs-Maint	11742000	11742000	3,387.71
505000	Other Operating Exp	11742000	11742000	3,319.22
505000	Other Operating Exp	11742000	11742000	29,244.37
505000	Other Operating Exp	11742000	11742000	(29,244.37)
800000	Lbr Alloc	11742000	11742000	93,915.62
804000	WBS ST Lbr	11742000	11742000	(104,940.80)
804020	WBS ST Material	11742000	11742000	(10,807.73)
804030	WBS ST Services	11742000	11742000	(31,844.89)
804040	WBS ST Other	11742000	11742000	(6,946.89)
804110	WBS ST OH Benefit	11742000	11742000	(261.00)
505000	Other Operating Exp	11742000	11920000	-
500300	Outside Svs	11742000	11742000	1,838.33
505000	Other Operating Exp	11742000	11920000	317.84
505000	Other Operating Exp	11742000	11871000	113,241.61
				102,511.76

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
521020	Gas Pur	11804001	11804000	9,349,082.37
521020	Gas Pur	11804001	11804000	(14,591.08)
521030	Gas Pur Dmnd Transp	11804001	11804000	402,133.11
521050	Gas Pur Cashouts	11804002	11804000	47,117.65
521060	Gas Pur Cap Release	11804001	11804000	(399,724.03)
521060	Gas Pur Cap Release	11804003	11804000	(312,443.95)
521070	Gas Pur Imbalances	11804001	11804000	7,618.14
521190	Gas Pur Dlvrd Strg	11804001	11804000	4,354.79
804040	WBS ST Other	11804000	11804000	(12,157,610.71)
505000	Other Operating Exp	11804000	11920000	-
521020	Gas Pur	11804000	11920000	65,147,884.03
521020	Gas Pur	11804000	11920000	1,701,450.00
521020	Gas Pur	11804000	11920000	18,983,174.29
521020	Gas Pur	11804000	11920000	(4,627,791.27)
521020	Gas Pur	11804001	11920000	4,300,281.18

521020	Gas Pur	11804001	11920000	1,254.96
521020	Gas Pur	11804001	11920000	3,836,069.85
521020	Gas Pur	11804001	11920000	(3,836,069.85)
521040	Gas Pur Def Costs	11804000	11920000	(69,669,243.64)
521040	Gas Pur Def Costs	11804000	11920000	(28,610,830.26)
521040	Gas Pur Def Costs	11804000	11920000	77,615.95
521040	Gas Pur Def Costs	11804000	11920000	(47,117.65)
521060	Gas Pur Cap Release	11804000	11920000	(3,614,180.60)
521060	Gas Pur Cap Release	11804000	11920000	(685,373.17)
521060	Gas Pur Cap Release	11804000	11920000	312,423.53
521060	Gas Pur Cap Release	11804003	11920000	1,246.88
521060	Gas Pur Cap Release	11804003	11920000	(598,020.71)
521060	Gas Pur Cap Release	11804003	11920000	(5,325.62)
521060	Gas Pur Cap Release	11804003	11920000	(400,958.18)
521060	Gas Pur Cap Release	11804003	11920000	400,958.18
521070	Gas Pur Imbalances	11804000	11920000	(157,212.46)
521070	Gas Pur Imbalances	11804000	11920000	1,587.45
521070	Gas Pur Imbalances	11804000	11920000	7,618.14
521070	Gas Pur Imbalances	11804000	11920000	(7,618.14)
521020	Gas Pur	11804001	11920000	885.32
521070	Gas Pur Imbalances	11804000	11480000	(354,697.92)
521020	Gas Pur	11804001	11804000	260,651.37
804040	WBS ST Other	11804000	11804000	(278,984.71)
521020	Gas Pur	11804000	11920000	1,651,928.34
521020	Gas Pur	11804000	11920000	402,496.26
521020	Gas Pur	11804000	11920000	(79,685.79)
521020	Gas Pur	11804001	11920000	79,476.71
521020	Gas Pur	11804001	11920000	78,635.34
521020	Gas Pur	11804001	11920000	47,097.96
521020	Gas Pur	11804001	11920000	(47,097.96)
521040	Gas Pur Def Costs	11804000	11920000	(1,769,371.39)
521040	Gas Pur Def Costs	11804000	11920000	(783,795.55)
521060	Gas Pur Cap Release	11804003	11920000	(5,325.62)
521060	Gas Pur Cap Release	11804003	11920000	5,325.62
521020	Gas Pur	11804001	11920000	37,965.75
				(21,316,737.09)

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
521030	Gas Pur Dmnd Transp	11804101	11804000	3,069,742.43
521030	Gas Pur Dmnd Transp	11804100	11920000	12,762,669.33
521030	Gas Pur Dmnd Transp	11804100	11920000	3,530,042.52
521030	Gas Pur Dmnd Transp	11804100	11920000	(1,701,618.95)
521030	Gas Pur Dmnd Transp	11804101	11920000	(6,305.84)
521030	Gas Pur Dmnd Transp	11804101	11920000	1,564,031.36
521030	Gas Pur Dmnd Transp	11804101	11920000	19,421.10
521030	Gas Pur Dmnd Transp	11804101	11920000	1,749,151.40
521030	Gas Pur Dmnd Transp	11804101	11920000	(1,749,151.40)

521030	Gas Pur Dmnd Transp	11804101	11804000	18,333.34
521030	Gas Pur Dmnd Transp	11804100	11920000	80,357.47
521030	Gas Pur Dmnd Transp	11804100	11920000	20,630.17
521030	Gas Pur Dmnd Transp	11804100	11920000	(9,166.67)
521030	Gas Pur Dmnd Transp	11804101	11920000	19,584.65
521030	Gas Pur Dmnd Transp	11804101	11920000	(19,584.65)
521030	Gas Pur Dmnd Transp	11804101	11920000	9,166.67
521030	Gas Pur Dmnd Transp	11804101	11920000	(9,166.67)
				19,348,136.26

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
521180	Gas Pur Wthdn Strg	11805000	11804000	2,136.93
521190	Gas Pur Dlvrd Strg	11805000	11804000	435.20
521090	Gas Pur Other	11805000	11920000	53,541.18
521130	Gas Pur PGA Rec Pub	11805000	11920000	65,359.00
521130	Gas Pur PGA Rec Pub	11805000	11920000	(32,658.64)
521190	Gas Pur Dlvrd Strg	11805000	11920000	3,094.31
521190	Gas Pur Dlvrd Strg	11805000	11920000	(1,168,098.27)
521190	Gas Pur Dlvrd Strg	11805000	11920000	4,354.76
521190	Gas Pur Dlvrd Strg	11805000	11920000	(4,354.76)
521180	Gas Pur Wthdn Strg	11805000	11920000	2,000.46
				(1,074,189.83)

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
521100	Gas Pur PGA Rec Res	11805100	11920000	31,905,729.67
521100	Gas Pur PGA Rec Res	11805100	11920000	13,622,218.86
521100	Gas Pur PGA Rec Res	11805101	11920000	1,990,891.34
521100	Gas Pur PGA Rec Res	11805101	11920000	23,845,969.38
521100	Gas Pur PGA Rec Res	11805101	11920000	(11,908,849.24)
521110	Gas Pur PGA Rec Com	11805100	11920000	22,897,443.42
521110	Gas Pur PGA Rec Com	11805100	11920000	10,172,400.90
521110	Gas Pur PGA Rec Com	11805102	11920000	1,465,058.06
521110	Gas Pur PGA Rec Com	11805102	11920000	19,515,269.50
521110	Gas Pur PGA Rec Com	11805102	11920000	(9,178,231.91)
521120	Gas Pur PGA Rec Ind	11805100	11920000	4,546.97
521120	Gas Pur PGA Rec Ind	11805100	11920000	6,777.56
521120	Gas Pur PGA Rec Ind	11805103	11920000	10.08
521130	Gas Pur PGA Rec Pub	11805100	11920000	6,049.73
521130	Gas Pur PGA Rec Pub	11805100	11920000	2,735.98
521100	Gas Pur PGA Rec Res	11805100	11920000	430,118.70
521100	Gas Pur PGA Rec Res	11805100	11920000	19,585.42
521100	Gas Pur PGA Rec Res	11805101	11920000	1,863.88
521100	Gas Pur PGA Rec Res	11805101	11920000	158,002.25
521100	Gas Pur PGA Rec Res	11805101	11920000	(78,914.01)
521110	Gas Pur PGA Rec Com	11805100	11920000	1,614,468.49
521110	Gas Pur PGA Rec Com	11805100	11920000	72,358.51
521110	Gas Pur PGA Rec Com	11805102	11920000	28,210.71

521110	Gas Pur PGA Rec Com	11805102	11920000	705,554.42
521110	Gas Pur PGA Rec Com	11805102	11920000	(345,263.53)
				106,954,005.14

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
521180	Gas Pur Wthdn Strg	11808100	11920000	4,574,093.73
521180	Gas Pur Wthdn Strg	11808100	11920000	2,709,201.34
521180	Gas Pur Wthdn Strg	11808100	11920000	8,879.73
521180	Gas Pur Wthdn Strg	11808100	11920000	(2,232.10)
521180	Gas Pur Wthdn Strg	11808100	11920000	152,459.82
521180	Gas Pur Wthdn Strg	11808100	11920000	39,069.97
				7,481,472.49

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
505000	Other Operating Exp	11844200	11844200	27,195.00
804040	WBS ST Other	11844000	11844000	(2,472.23)
804040	WBS ST Other	11844200	11844200	(27,195.00)
505000	Other Operating Exp	11844200	11920000	-
				(2,472.23)

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11846200	11846200	205.96
800000	Lbr Alloc	11846200	11846200	400.49
804000	WBS ST Lbr	11846200	11846200	(606.45)
505000	Other Operating Exp	11846200	11920000	-
500000	Salaries and Wages	11846200	11920000	1,165.48
505000	Other Operating Exp	11846200	11871000	5,264.11
				6,429.59

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
800000	Lbr Alloc	11850000	11850000	306.40
804000	WBS ST Lbr	11850000	11850000	(306.40)
505000	Other Operating Exp	11850000	11920000	-
				-

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
800000	Lbr Alloc	11863000	11863000	575.30
804000	WBS ST Lbr	11863000	11863000	(575.30)
505000	Other Operating Exp	11863000	11920000	-
500000	Salaries and Wages	11863000	11920000	7,559.01
500100	Vacation & Other TO	11863000	11920000	251.64
				7,810.65

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11870000	11870000	10,798.64

500300	Outside Svs	11870000	11870000	845.28
800000	Lbr Alloc	11870000	11870000	1,582.62
804000	WBS ST Lbr	11870000	11870000	(12,381.26)
804030	WBS ST Services	11870000	11870000	(845.28)
505000	Other Operating Exp	11870000	11920000	-
500000	Salaries and Wages	11870000	11920000	5,957.32
505000	Other Operating Exp	11870000	11920000	232.52
500000	Salaries and Wages	11870000	11870000	399,218.14
500000	Salaries and Wages	11870000	11870000	(8,573.13)
500010	Overtime	11870000	11870000	(62.59)
500050	AllocCorp Lbr Leg	11870000	11870000	8,487.20
500100	Vacation & Other TO	11870000	11870000	13,825.74
505000	Other Operating Exp	11870000	11870000	77,444.66
505000	Other Operating Exp	11870000	11870000	24,483.93
803000	Assess Lbr	11870000	11870000	(17,014.36)
803080	Assess Meals	11870000	11870000	78.74
803085	Assess Travel	11870000	11870000	327.27
803110	Assess OH Benefit	11870000	11870000	227.39
853000	Assess Lbr-Intrc	11870000	11870000	(8,635.72)
853080	Assess Meals -Intrc	11870000	11870000	37.79
853085	Assess Travel-Intrc	11870000	11870000	174.14
853110	As OH BenIntrc	11870000	11870000	(63.41)
500000	Salaries and Wages	11870000	11870000	(11,866.47)
500050	AllocCorp Lbr Leg	11870000	11870000	10,956.46
500100	Vacation & Other TO	11870000	11870000	4,845.59
803000	Assess Lbr	11870000	11870000	(41,906.79)
803020	Assess Material	11870000	11870000	239.95
803040	Assess Other	11870000	11870000	12.62
803080	Assess Meals	11870000	11870000	270.14
803085	Assess Travel	11870000	11870000	2,071.67
804000	WBS ST Lbr	11870000	11870000	132,210.39
804020	WBS ST Material	11870000	11870000	188.50
804030	WBS ST Services	11870000	11870000	38,356.74
804040	WBS ST Other	11870000	11870000	11,161.52
804050	WBS ST Fleet	11870000	11870000	1,572.13
804085	WBS ST Travel	11870000	11870000	2,381.25
853000	Assess Lbr-Intrc	11870000	11870000	(11,866.47)
853080	Assess Meals -Intrc	11870000	11870000	170.82
853085	Assess Travel-Intrc	11870000	11870000	1,057.84
853110	As OH BenIntrc	11870000	11870000	(318.65)
500000	Salaries and Wages	11870000	11871000	1,257.98
505000	Other Operating Exp	11870000	11871000	62,032.09
				698,972.94

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
702000	BS Lbr Offset	11871000	11871000	(37,164.34)
803000	Assess Lbr	11871000	11871000	37,164.34
804000	WBS ST Lbr	11871000	11871000	(6,088.56)
854000	WBS ST Lbr-Intrc	11871000	11871000	6,088.56
505000	Other Operating Exp	11871000	11920000	(6,955.41)
500000	Salaries and Wages	11871000	11871000	345,394.73
500000	Salaries and Wages	11871000	11871000	35,815.90
500000	Salaries and Wages	11871000	11871000	(6,955.41)
500010	Overtime	11871000	11871000	3,137.63
500050	AllocCorp Lbr Leg	11871000	11871000	(22,296.13)
500100	Vacation & Other TO	11871000	11871000	(38,306.16)
505000	Other Operating Exp	11871000	11871000	(13,243.60)
505100	Cost Alloc to Cap	11871000	11871000	(113,126.03)
803000	Assess Lbr	11871000	11871000	(4,840.35)
803000	Assess Lbr	11871000	11871000	(2,243.45)
804000	WBS ST Lbr	11871000	11871000	29,948.11
804040	WBS ST Other	11871000	11871000	216.73
804110	WBS ST OH Benefit	11871000	11871000	46.23
804112	WBS ST OH Payroll Tx	11871000	11871000	5.64
804113	WBS ST OH Pen/OPEB	11871000	11871000	5.76
804114	WBS ST OH Prop Ins	11871000	11871000	3.24
853000	Assess Lbr-Intrc	11871000	11871000	22,051.03
853040	Assess Other-Intrc	11871000	11871000	245.10
500000	Salaries and Wages	11871000	11871000	(2,431.79)
500010	Overtime	11871000	11871000	1,705.16
500050	AllocCorp Lbr Leg	11871000	11871000	736.63
500100	Vacation & Other TO	11871000	11871000	4,448.98
505000	Other Operating Exp	11871000	11871000	(292.09)
505100	Cost Alloc to Cap	11871000	11871000	(347.87)
803000	Assess Lbr	11871000	11871000	31,727.50
803000	Assess Lbr	11871000	11871000	(10,558.22)
803040	Assess Other	11871000	11871000	1,980.39
803080	Assess Meals	11871000	11871000	198.19
853000	Assess Lbr-Intrc	11871000	11871000	(726.63)
853110	As OH BenIntrc	11871000	11871000	(10.00)
500000	Salaries and Wages	11871000	11871000	13,714.72
500010	Overtime	11871000	11871000	4,585.65
500050	AllocCorp Lbr Leg	11871000	11871000	(18,240.37)
500100	Vacation & Other TO	11871000	11871000	1,880.18
505000	Other Operating Exp	11871000	11871000	(11,594.26)
505100	Cost Alloc to Cap	11871000	11871000	(13,808.76)
803000	Assess Lbr	11871000	11871000	22,284.26
803000	Assess Lbr	11871000	11871000	(2,610.36)

853000	Assess Lbr-Intrc	11871000	11871000	18,300.37
853110	As OH BenIntrc	11871000	11871000	(60.00)
500000	Salaries and Wages	11871000	11871000	(3,854.35)
500010	Overtime	11871000	11871000	1,407.43
500050	AllocCorp Lbr Leg	11871000	11871000	2,697.92
500100	Vacation & Other TO	11871000	11871000	8,263.99
505000	Other Operating Exp	11871000	11871000	(195.88)
505100	Cost Alloc to Cap	11871000	11871000	(233.29)
803000	Assess Lbr	11871000	11871000	65,156.04
803000	Assess Lbr	11871000	11871000	(21,752.31)
853000	Assess Lbr-Intrc	11871000	11871000	(2,446.92)
853110	As OH BenIntrc	11871000	11871000	(251.00)
				318,576.87

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11874000	11874000	21,970.09
500010	Overtime	11874000	11874000	10,048.63
500100	Vacation & Other TO	11874000	11874000	980.20
500115	Ben Offst	11874000	11874000	2,845.09
500300	Outside Svs	11874000	11199999	7,163.18
500300	Outside Svs	11874000	11199999	245,287.80
500300	Outside Svs	11874000	11874000	159,644.56
500300	Outside Svs	11874000	11874000	528.00
501210	Fleet-Fuel	11874000	11874000	493.72
505000	Other Operating Exp	11874000	11874000	2,598.33
505000	Other Operating Exp	11874000	11874000	8,107.00
800000	Lbr Alloc	11874000	11874000	43,067.96
800000	Lbr Alloc	11874000	11874000	636,075.71
802000	Settle Lbr	11874000	11874000	(13,251.70)
802000	Settle Lbr	11874000	11874000	(443.48)
802000	Settle Lbr	11874000	11874000	7,013.11
802020	Settle Material	11874000	11874000	(1,005.87)
802020	Settle Material	11874000	11874000	295.58
804000	WBS ST Lbr	11874000	11874000	(675,107.54)
804020	WBS ST Material	11874000	11874000	(17,494.18)
804030	WBS ST Services	11874000	11874000	(159,644.56)
804040	WBS ST Other	11874000	11874000	(13,155.33)
804050	WBS ST Fleet	11874000	11874000	(493.72)
804110	WBS ST OH Benefit	11874000	11874000	(3,825.29)
505000	Other Operating Exp	11874000	11920000	-
500000	Salaries and Wages	11874000	11920000	57,497.45
505000	Other Operating Exp	11874000	11920000	709,809.64
500000	Salaries and Wages	11874000	11920000	2,713,458.98
505000	Other Operating Exp	11874000	11920000	414,933.06

500000	Salaries and Wages	11874000	11870000	12,354.27
505000	Other Operating Exp	11874000	11870000	10,032.64
500000	Salaries and Wages	11874000	11874000	1,118.68
500010	Overtime	11874000	11874000	46.72
500100	Vacation & Other TO	11874000	11874000	567.50
500300	Outside Svs	11874000	11874000	24,694.12
800000	Lbr Alloc	11874000	11874000	3,123.22
802000	Settle Lbr	11874000	11874000	29.57
804000	WBS ST Lbr	11874000	11874000	(4,318.19)
804030	WBS ST Services	11874000	11874000	(24,694.12)
804110	WBS ST OH Benefit	11874000	11874000	(567.50)
500000	Salaries and Wages	11874000	11920000	40,115.08
505000	Other Operating Exp	11874000	11920000	48,887.47
				4,268,785.88

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11875000	11875000	195.19
500010	Overtime	11875000	11875000	77.87
500100	Vacation & Other TO	11875000	11875000	186.88
500300	Outside Svs	11875000	11875000	2,622.59
800000	Lbr Alloc	11875000	11875000	21,897.60
804000	WBS ST Lbr	11875000	11875000	(22,170.66)
804030	WBS ST Services	11875000	11875000	(2,622.59)
804110	WBS ST OH Benefit	11875000	11875000	(186.88)
505000	Other Operating Exp	11875000	11920000	-
500300	Outside Svs	11875000	11875000	3,659.29
800000	Lbr Alloc	11875000	11875000	11,632.42
804000	WBS ST Lbr	11875000	11875000	(11,632.42)
804030	WBS ST Services	11875000	11875000	(3,659.29)
500000	Salaries and Wages	11875000	11920000	11,263.92
500930	Util Exp-Cust Instal	11875000	11920000	1,015.00
				12,278.92

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11878000	11878000	23,379.45
500010	Overtime	11878000	11878000	2,309.76
500100	Vacation & Other TO	11878000	11878000	888.64
800000	Lbr Alloc	11878000	11878000	218,685.08
800000	Lbr Alloc	11878000	11878000	75,768.05
802000	Settle Lbr	11878000	11878000	(73,154.42)
802000	Settle Lbr	11878000	11878000	(392.83)
802000	Settle Lbr	11878000	11878000	123,153.45
804000	WBS ST Lbr	11878000	11878000	(224,610.71)
804020	WBS ST Material	11878000	11878000	(5,948.99)

804110	WBS ST OH Benefit	11878000	11878000	(888.64)
505000	Other Operating Exp	11878000	11920000	-
500000	Salaries and Wages	11878000	11920000	717,782.99
505000	Other Operating Exp	11878000	11920000	229,549.56
802000	Settle Lbr	11878000	11878000	718.45
804000	WBS ST Lbr	11878000	11878000	(718.45)
				1,086,521.39

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11879000	11879000	9,338.67
500010	Overtime	11879000	11879000	591.36
500100	Vacation & Other TO	11879000	11879000	1,143.49
500300	Outside Svs	11879000	11879000	4,587.00
505000	Other Operating Exp	11879000	11879000	881.37
800000	Lbr Alloc	11879000	11879000	16,568.07
800000	Lbr Alloc	11879000	11879000	113,043.62
802000	Settle Lbr	11879000	11879000	63,279.00
802020	Settle Material	11879000	11879000	2,169.76
804000	WBS ST Lbr	11879000	11879000	(186,252.65)
804020	WBS ST Material	11879000	11879000	(4,368.47)
804030	WBS ST Services	11879000	11879000	(4,587.00)
804040	WBS ST Other	11879000	11879000	(2,047.42)
804110	WBS ST OH Benefit	11879000	11879000	(1,143.49)
505000	Other Operating Exp	11879000	11920000	-
500000	Salaries and Wages	11879000	11920000	514,794.70
500930	Util Exp-Cust Instal	11879000	11920000	(69,828.73)
500300	Outside Svs	11879000	11879000	538.98
505000	Other Operating Exp	11879000	11879000	1,105.31
800000	Lbr Alloc	11879000	11879000	3,188.95
802000	Settle Lbr	11879000	11879000	1,784.21
804000	WBS ST Lbr	11879000	11879000	(4,973.16)
804030	WBS ST Services	11879000	11879000	(538.98)
804040	WBS ST Other	11879000	11879000	(1,105.31)
500000	Salaries and Wages	11879000	11920000	16,409.54
500930	Util Exp-Cust Instal	11879000	11920000	2,136.18
				476,715.00

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11880000	11880000	7,941.09
500010	Overtime	11880000	11880000	945.08
500100	Vacation & Other TO	11880000	11880000	2,617.18
500300	Outside Svs	11880000	11880000	(26.60)
500300	Outside Svs	11880000	11880000	33,513.45
500300	Outside Svs	11880000	11880000	3.96

500300	Outside Svs	11880000	11880000	1,007.45
500330	Outside Svs-Ser Main	11880000	11880000	4,816.08
501210	Fleet-Fuel	11880000	11880000	52,353.84
501210	Fleet-Fuel	11880000	11880000	1,128.92
501220	Fleet-Repair/Main	11880000	11880000	5,909.34
501230	Fleet-Permit/Inspect	11880000	11880000	479.07
502300	Facility Costs	11880000	11880000	14,190.52
505000	Other Operating Exp	11880000	11880000	254.95
505000	Other Operating Exp	11880000	11880000	16,786.50
505000	Other Operating Exp	11880000	11880000	52,353.84
505000	Other Operating Exp	11880000	11880000	(52,353.84)
505500	Collection System	11880000	11880000	(6,313.80)
505500	Collection System	11880000	11880000	6,313.80
702000	BS Lbr Offset	11880000	11880000	(7,455.06)
800000	Lbr Alloc	11880000	11880000	53,996.74
803000	Assess Lbr	11880000	11880000	7,455.06
804000	WBS ST Lbr	11880000	11880000	(62,882.91)
804020	WBS ST Material	11880000	11880000	(23,109.38)
804030	WBS ST Services	11880000	11880000	(39,314.34)
804040	WBS ST Other	11880000	11880000	(33,871.44)
804050	WBS ST Fleet	11880000	11880000	(59,871.17)
804085	WBS ST Travel	11880000	11880000	-
804110	WBS ST OH Benefit	11880000	11880000	(2,617.18)
505000	Other Operating Exp	11880000	11920000	(20,100.84)
500000	Salaries and Wages	11880000	11880000	9,475.27
500000	Salaries and Wages	11880000	11880000	(20,100.84)
500050	AllocCorp Lbr Leg	11880000	11880000	(5,236.99)
500100	Vacation & Other TO	11880000	11880000	(7,618.81)
505000	Other Operating Exp	11880000	11880000	(21,601.10)
505100	Cost Alloc to Cap	11880000	11880000	(25,726.91)
803000	Assess Lbr	11880000	11880000	5,624.85
803000	Assess Lbr	11880000	11880000	(7,455.06)
803020	Assess Material	11880000	11880000	1,345.77
803040	Assess Other	11880000	11880000	585.39
803050	Assess Fleet - Asses	11880000	11880000	147.28
803080	Assess Meals	11880000	11880000	520.52
803085	Assess Travel	11880000	11880000	1,399.63
804000	WBS ST Lbr	11880000	11880000	67,917.49
804030	WBS ST Services	11880000	11880000	12,370.08
804040	WBS ST Other	11880000	11880000	20,568.48
853000	Assess Lbr-Intrc	11880000	11880000	9,475.28
853110	As OH BenIntrc	11880000	11880000	(4,238.29)
500000	Salaries and Wages	11880000	11920000	497,019.41
505000	Other Operating Exp	11880000	11920000	498,209.56

500000	Salaries and Wages	11880000	11880000	(5,140.83)
500010	Overtime	11880000	11880000	(116.21)
500050	AllocCorp Lbr Leg	11880000	11880000	5,257.04
500100	Vacation & Other TO	11880000	11880000	8,588.66
803000	Assess Lbr	11880000	11880000	(13,932.12)
803080	Assess Meals	11880000	11880000	5,447.80
803085	Assess Travel	11880000	11880000	790.58
804000	WBS ST Lbr	11880000	11880000	71,404.08
804030	WBS ST Services	11880000	11880000	4,802.54
804040	WBS ST Other	11880000	11880000	8,472.78
804050	WBS ST Fleet	11880000	11880000	58,263.18
853000	Assess Lbr-Intrc	11880000	11880000	(5,257.04)
500000	Salaries and Wages	11880000	11871000	14,724.01
505000	Other Operating Exp	11880000	11871000	2,850.24
500000	Salaries and Wages	11880000	11880000	18,779.88
500010	Overtime	11880000	11880000	6,282.00
500050	AllocCorp Lbr Leg	11880000	11880000	(23,888.68)
500100	Vacation & Other TO	11880000	11880000	1,385.36
803000	Assess Lbr	11880000	11880000	(13,494.60)
803040	Assess Other	11880000	11880000	0.99
803050	Assess Fleet - Asses	11880000	11880000	105.53
803085	Assess Travel	11880000	11880000	488.75
804000	WBS ST Lbr	11880000	11880000	52,130.38
804020	WBS ST Material	11880000	11880000	8,977.94
804030	WBS ST Services	11880000	11880000	20,463.60
804040	WBS ST Other	11880000	11880000	45,160.86
804050	WBS ST Fleet	11880000	11880000	11,093.93
804080	WBS ST Meals	11880000	11880000	50.72
804085	WBS ST Travel	11880000	11880000	16,161.61
804110	WBS ST OH Benefit	11880000	11880000	663.78
853000	Assess Lbr-Intrc	11880000	11880000	25,061.88
853110	As OH BenIntrc	11880000	11880000	(1,173.20)
500000	Salaries and Wages	11880000	11880000	5,823.55
500010	Overtime	11880000	11880000	1,528.97
500050	AllocCorp Lbr Leg	11880000	11880000	(7,352.52)
500100	Vacation & Other TO	11880000	11880000	39.80
803000	Assess Lbr	11880000	11880000	(4,263.66)
804000	WBS ST Lbr	11880000	11880000	8,309.73
804020	WBS ST Material	11880000	11880000	178.76
804030	WBS ST Services	11880000	11880000	69,467.26
804040	WBS ST Other	11880000	11880000	2,877.77
804080	WBS ST Meals	11880000	11880000	240.85
804110	WBS ST OH Benefit	11880000	11880000	3,093.99
853000	Assess Lbr-Intrc	11880000	11880000	7,352.52

500000	Salaries and Wages	11880000	11880000	14,174.80
500010	Overtime	11880000	11880000	1,774.20
500050	AllocCorp Lbr Leg	11880000	11880000	(15,949.00)
500100	Vacation & Other TO	11880000	11880000	1,444.08
803000	Assess Lbr	11880000	11880000	(3,651.64)
803040	Assess Other	11880000	11880000	552.44
804000	WBS ST Lbr	11880000	11880000	6,476.14
804030	WBS ST Services	11880000	11880000	409.84
804040	WBS ST Other	11880000	11880000	517.85
804110	WBS ST OH Benefit	11880000	11880000	(36.40)
853000	Assess Lbr-Intrc	11880000	11880000	15,949.00
500000	Salaries and Wages	11880000	11880000	9,363.49
500010	Overtime	11880000	11880000	13,384.51
500050	AllocCorp Lbr Leg	11880000	11880000	(22,396.00)
500100	Vacation & Other TO	11880000	11880000	4,512.55
803000	Assess Lbr	11880000	11880000	(14,991.48)
803020	Assess Material	11880000	11880000	384.66
803040	Assess Other	11880000	11880000	1,510.80
804000	WBS ST Lbr	11880000	11880000	266,169.36
804020	WBS ST Material	11880000	11880000	21,820.41
804030	WBS ST Services	11880000	11880000	106,697.64
804040	WBS ST Other	11880000	11880000	46,804.01
804050	WBS ST Fleet	11880000	11880000	26,151.94
804085	WBS ST Travel	11880000	11880000	39,048.03
853000	Assess Lbr-Intrc	11880000	11880000	22,748.00
853110	As OH BenIntrc	11880000	11880000	(352.00)
500000	Salaries and Wages	11880000	11880000	61,724.27
500010	Overtime	11880000	11880000	24,779.55
500050	AllocCorp Lbr Leg	11880000	11880000	(86,153.10)
500100	Vacation & Other TO	11880000	11880000	9,610.33
500255	Service Awards	11880000	11880000	162.43
803000	Assess Lbr	11880000	11880000	(45,027.51)
803020	Assess Material	11880000	11880000	708.90
803040	Assess Other	11880000	11880000	1,267.27
803080	Assess Meals	11880000	11880000	1,422.21
803110	Assess OH Benefit	11880000	11880000	108.28
804000	WBS ST Lbr	11880000	11880000	268,291.13
804020	WBS ST Material	11880000	11880000	22,369.03
804030	WBS ST Services	11880000	11880000	262,613.11
804040	WBS ST Other	11880000	11880000	232,614.91
804050	WBS ST Fleet	11880000	11880000	684.23
853000	Assess Lbr-Intrc	11880000	11880000	86,503.82
853080	Assess Meals -Intrc	11880000	11880000	52.65
853110	As OH BenIntrc	11880000	11880000	(403.37)

500000	Salaries and Wages	11880000	11880000	12,000.43
500010	Overtime	11880000	11880000	12,235.24
500050	AllocCorp Lbr Leg	11880000	11880000	(23,507.30)
500100	Vacation & Other TO	11880000	11880000	5,116.19
500255	Service Awards	11880000	11880000	162.43
803000	Assess Lbr	11880000	11880000	32,711.55
803040	Assess Other	11880000	11880000	2,880.45
803080	Assess Meals	11880000	11880000	205.68
804000	WBS ST Lbr	11880000	11880000	111,469.13
804020	WBS ST Material	11880000	11880000	4,335.37
804030	WBS ST Services	11880000	11880000	30,172.55
804040	WBS ST Other	11880000	11880000	3,524.66
804050	WBS ST Fleet	11880000	11880000	205.16
853000	Assess Lbr-Intrc	11880000	11880000	24,235.67
853110	As OH BenIntrc	11880000	11880000	(728.37)
500000	Salaries and Wages	11880000	11880000	3,044.08
500010	Overtime	11880000	11880000	13,638.72
500050	AllocCorp Lbr Leg	11880000	11880000	(16,147.93)
500100	Vacation & Other TO	11880000	11880000	2,274.99
803000	Assess Lbr	11880000	11880000	(35,427.11)
803020	Assess Material	11880000	11880000	160.75
803040	Assess Other	11880000	11880000	30.97
803080	Assess Meals	11880000	11880000	63.83
803110	Assess OH Benefit	11880000	11880000	518.38
804000	WBS ST Lbr	11880000	11880000	248,670.87
804020	WBS ST Material	11880000	11880000	6,742.31
804030	WBS ST Services	11880000	11880000	40,326.20
804040	WBS ST Other	11880000	11880000	9,928.44
804050	WBS ST Fleet	11880000	11880000	11,592.43
804085	WBS ST Travel	11880000	11880000	17,506.57
804110	WBS ST OH Benefit	11880000	11880000	1,004.03
853000	Assess Lbr-Intrc	11880000	11880000	16,682.80
853110	As OH BenIntrc	11880000	11880000	(534.87)
500000	Salaries and Wages	11880000	11880000	7,831.03
500010	Overtime	11880000	11880000	5,455.83
500050	AllocCorp Lbr Leg	11880000	11880000	(13,256.86)
500100	Vacation & Other TO	11880000	11880000	1,615.40
803000	Assess Lbr	11880000	11880000	(9,960.19)
803020	Assess Material	11880000	11880000	216.90
803040	Assess Other	11880000	11880000	211.96
803050	Assess Fleet - Asses	11880000	11880000	85.93
804000	WBS ST Lbr	11880000	11880000	103,069.91
804020	WBS ST Material	11880000	11880000	7,433.28
804030	WBS ST Services	11880000	11880000	90,729.99

804040	WBS ST Other	11880000	11880000	20,684.56
853000	Assess Lbr-Intrc	11880000	11880000	13,286.86
853110	As OH BenIntrc	11880000	11880000	(30.00)
500000	Salaries and Wages	11880000	11880000	2,395.36
500010	Overtime	11880000	11880000	2,533.06
500050	AllocCorp Lbr Leg	11880000	11880000	(4,928.42)
500100	Vacation & Other TO	11880000	11880000	1,104.15
803000	Assess Lbr	11880000	11880000	(7,601.42)
803040	Assess Other	11880000	11880000	16.64
804000	WBS ST Lbr	11880000	11880000	70,229.49
804020	WBS ST Material	11880000	11880000	1,658.09
804030	WBS ST Services	11880000	11880000	956.69
804040	WBS ST Other	11880000	11880000	33.98
804050	WBS ST Fleet	11880000	11880000	382.14
804110	WBS ST OH Benefit	11880000	11880000	11,881.89
853000	Assess Lbr-Intrc	11880000	11880000	4,928.42
500300	Outside Svs	11880000	11880000	1,167.28
501710	Lic/Fee/Per-Other	11880000	11880000	216.00
505000	Other Operating Exp	11880000	11880000	1,566.69
800000	Lbr Alloc	11880000	11880000	45,231.96
804000	WBS ST Lbr	11880000	11880000	(45,231.96)
804020	WBS ST Material	11880000	11880000	(316.50)
804030	WBS ST Services	11880000	11880000	(1,167.28)
804040	WBS ST Other	11880000	11880000	(1,859.84)
500000	Salaries and Wages	11880000	11920000	1,154.90
505000	Other Operating Exp	11880000	11920000	34,929.56
				3,664,128.93

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500300	Outside Svs	11881000	11881000	15,516.53
800000	Lbr Alloc	11881000	11881000	70.99
804000	WBS ST Lbr	11881000	11881000	(70.99)
804030	WBS ST Services	11881000	11881000	(15,516.53)
505000	Other Operating Exp	11881000	11920000	-
500930	Util Exp-Cust Instal	11881000	11920000	20,428.73
				20,428.73

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
800000	Lbr Alloc	11885000	11885000	110,718.57
804000	WBS ST Lbr	11885000	11885000	(110,718.57)
505000	Other Operating Exp	11885000	11920000	-
				-

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11886000	11886000	699.52

500300	Outside Svs	11886000	11886000	1,344.72
505000	Other Operating Exp	11886000	11886000	148.65
505000	Other Operating Exp	11886000	11886000	10,370.00
800000	Lbr Alloc	11886000	11886000	33,481.43
804000	WBS ST Lbr	11886000	11886000	(34,180.95)
804030	WBS ST Services	11886000	11886000	(1,344.72)
804040	WBS ST Other	11886000	11886000	(20,888.45)
505000	Other Operating Exp	11886000	11920000	-
500000	Salaries and Wages	11886000	11886000	(2,084.08)
500010	Overtime	11886000	11886000	(39.17)
500050	AllocCorp Lbr Leg	11886000	11886000	2,123.24
500100	Vacation & Other TO	11886000	11886000	2,863.17
802110	Settle OH Benefit	11886000	11886000	(26,261.13)
803000	Assess Lbr	11886000	11886000	(2,171.92)
803020	Assess Material	11886000	11886000	4,791.98
803040	Assess Other	11886000	11886000	14.59
803080	Assess Meals	11886000	11886000	37.30
804000	WBS ST Lbr	11886000	11886000	32,100.47
804020	WBS ST Material	11886000	11886000	464.10
804030	WBS ST Services	11886000	11886000	14,097.54
804040	WBS ST Other	11886000	11886000	310,685.08
804050	WBS ST Fleet	11886000	11886000	3,566.40
804085	WBS ST Travel	11886000	11886000	5,401.90
853000	Assess Lbr-Intrc	11886000	11886000	(2,123.24)
500000	Salaries and Wages	11886000	11920000	62,751.20
505000	Other Operating Exp	11886000	11920000	141,784.44
500000	Salaries and Wages	11886000	11886000	39.42
505000	Other Operating Exp	11886000	11886000	24.00
800000	Lbr Alloc	11886000	11886000	3,388.25
804000	WBS ST Lbr	11886000	11886000	(3,427.67)
804020	WBS ST Material	11886000	11886000	(5.81)
804030	WBS ST Services	11886000	11886000	(2,777.50)
804040	WBS ST Other	11886000	11886000	(299.10)
500000	Salaries and Wages	11886000	11920000	3,189.15
505000	Other Operating Exp	11886000	11920000	1,663.57
				539,426.38

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11887000	11887000	495.20
500010	Overtime	11887000	11887000	2,506.72
500115	Ben Offst	11887000	11887000	311.44
500300	Outside Svs	11887000	11887000	214,591.04
500300	Outside Svs	11887000	11887000	3,689.41
500300	Outside Svs	11887000	11887000	4,555.02

500330	Outside Svs-Ser Main	11887000	11887000	10,959.72
505000	Other Operating Exp	11887000	11887000	1,270.43
505000	Other Operating Exp	11887000	11887000	1,138.04
505000	Other Operating Exp	11887000	11887000	338,234.82
505000	Other Operating Exp	11887000	11887000	(1,138.04)
505000	Other Operating Exp	11887000	11887000	(91,671.08)
800000	Lbr Alloc	11887000	11887000	23,534.61
800000	Lbr Alloc	11887000	11887000	160,164.47
802000	Settle Lbr	11887000	11887000	(8,835.99)
802000	Settle Lbr	11887000	11887000	17,279.44
802020	Settle Material	11887000	11887000	(98.65)
802020	Settle Material	11887000	11887000	98.65
802030	Settle Services	11887000	11887000	806.02
802040	Settle Other	11887000	11887000	-
804000	WBS ST Lbr	11887000	11887000	(180,445.83)
804020	WBS ST Material	11887000	11887000	(8,924.02)
804030	WBS ST Services	11887000	11887000	(230,911.80)
804040	WBS ST Other	11887000	11887000	(247,834.17)
804110	WBS ST OH Benefit	11887000	11887000	(311.44)
505000	Other Operating Exp	11887000	11920000	-
500000	Salaries and Wages	11887000	11920000	475,419.14
505000	Other Operating Exp	11887000	11920000	850,375.47
500000	Salaries and Wages	11887000	11870000	4,913.65
500000	Salaries and Wages	11887000	11887000	1,123.47
500010	Overtime	11887000	11887000	59.13
500300	Outside Svs	11887000	11887000	264.00
505000	Other Operating Exp	11887000	11887000	40.49
800000	Lbr Alloc	11887000	11887000	4,645.04
802000	Settle Lbr	11887000	11887000	1,360.82
804000	WBS ST Lbr	11887000	11887000	(7,188.46)
804030	WBS ST Services	11887000	11887000	(264.00)
804040	WBS ST Other	11887000	11887000	(40.49)
500000	Salaries and Wages	11887000	11920000	22,468.32
505000	Other Operating Exp	11887000	11920000	278,578.95
				1,641,219.54

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11889000	11889000	2,357.16
800000	Lbr Alloc	11889000	11889000	129.90
804000	WBS ST Lbr	11889000	11889000	(2,487.06)
505000	Other Operating Exp	11889000	11920000	-
				-

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022

500000	Salaries and Wages	11892000	11892000	5,029.34
500010	Overtime	11892000	11892000	1,517.49
500300	Outside Svs	11892000	11892000	94,482.30
500300	Outside Svs	11892000	11892000	7,817.88
500330	Outside Svs-Ser Main	11892000	11892000	14,176.58
505000	Other Operating Exp	11892000	11892000	139,418.75
505000	Other Operating Exp	11892000	11892000	(126,939.25)
800000	Lbr Alloc	11892000	11892000	2,057.48
800000	Lbr Alloc	11892000	11892000	76,518.09
802000	Settle Lbr	11892000	11892000	42,533.63
802020	Settle Material	11892000	11892000	2,866.03
802030	Settle Services	11892000	11892000	528.00
804000	WBS ST Lbr	11892000	11892000	(125,598.55)
804020	WBS ST Material	11892000	11892000	(6,906.50)
804030	WBS ST Services	11892000	11892000	(117,004.76)
804040	WBS ST Other	11892000	11892000	(12,479.50)
505000	Other Operating Exp	11892000	11920000	-
500000	Salaries and Wages	11892000	11920000	194,704.07
505000	Other Operating Exp	11892000	11920000	460,336.22
500300	Outside Svs	11892000	11892000	264.00
505000	Other Operating Exp	11892000	11892000	304.48
800000	Lbr Alloc	11892000	11892000	716.60
802000	Settle Lbr	11892000	11892000	443.48
804000	WBS ST Lbr	11892000	11892000	(1,160.08)
804030	WBS ST Services	11892000	11892000	(264.00)
804040	WBS ST Other	11892000	11892000	(304.48)
500000	Salaries and Wages	11892000	11920000	9,072.69
505000	Other Operating Exp	11892000	11920000	(320,217.56)
				341,912.43

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11893000	11893000	3,899.99
500010	Overtime	11893000	11893000	342.25
500100	Vacation & Other TO	11893000	11893000	9.60
500300	Outside Svs	11893000	11893000	133.88
505000	Other Operating Exp	11893000	11893000	320.27
505000	Other Operating Exp	11893000	11893000	12,525.00
800000	Lbr Alloc	11893000	11893000	52,404.39
802000	Settle Lbr	11893000	11893000	103,595.66
802020	Settle Material	11893000	11893000	798.56
804000	WBS ST Lbr	11893000	11893000	(160,242.29)
804020	WBS ST Material	11893000	11893000	(3,258.10)
804030	WBS ST Services	11893000	11893000	(133.88)
804040	WBS ST Other	11893000	11893000	(12,946.42)

804110	WBS ST OH Benefit	11893000	11893000	(9.60)
505000	Other Operating Exp	11893000	11920000	-
500000	Salaries and Wages	11893000	11920000	176,506.65
505000	Other Operating Exp	11893000	11920000	47,533.86
500000	Salaries and Wages	11893000	11893000	374.49
500010	Overtime	11893000	11893000	77.86
500100	Vacation & Other TO	11893000	11893000	332.24
505000	Other Operating Exp	11893000	11893000	83.53
800000	Lbr Alloc	11893000	11893000	5,975.06
802000	Settle Lbr	11893000	11893000	1,078.34
804000	WBS ST Lbr	11893000	11893000	(7,505.75)
804020	WBS ST Material	11893000	11893000	(211.06)
804040	WBS ST Other	11893000	11893000	(83.53)
804110	WBS ST OH Benefit	11893000	11893000	(332.24)
500000	Salaries and Wages	11893000	11920000	31,547.26
505000	Other Operating Exp	11893000	11920000	7,634.04
				260,450.06

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11894000	11894000	346.40
500300	Outside Svs	11894000	11894000	2,704.64
500300	Outside Svs	11894000	11894000	742.84
500500	Equip & Machin Rents	11894000	11894000	564.88
505000	Other Operating Exp	11894000	11894000	7,151.82
800000	Lbr Alloc	11894000	11894000	67,462.42
804000	WBS ST Lbr	11894000	11894000	(67,808.82)
804020	WBS ST Material	11894000	11894000	(29,656.42)
804030	WBS ST Services	11894000	11894000	(3,447.48)
804040	WBS ST Other	11894000	11894000	(7,831.90)
505000	Other Operating Exp	11894000	11920000	-
500000	Salaries and Wages	11894000	11920000	98,423.44
505000	Other Operating Exp	11894000	11920000	183,877.88
410400	Gas Rev FxTsp	11489400	11480000	(1,511.97)
410400	Gas Rev FxTsp	11489400	11480000	(185,253.75)
410400	Gas Rev FxTsp	11489400	11480000	1,511.97
500000	Salaries and Wages	11894000	11894000	149.94
500100	Vacation & Other TO	11894000	11894000	1.80
500300	Outside Svs	11894000	11894000	125.28
800000	Lbr Alloc	11894000	11894000	1,066.54
804000	WBS ST Lbr	11894000	11894000	(1,216.48)
804030	WBS ST Services	11894000	11894000	(125.28)
804110	WBS ST OH Benefit	11894000	11894000	(1.80)
500000	Salaries and Wages	11894000	11920000	5,264.49
505000	Other Operating Exp	11894000	11920000	862.00

				73,402.44

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11901000	11901000	6,107.17
500010	Overtime	11901000	11901000	(509.04)
800000	Lbr Alloc	11901000	11901000	29,601.59
804000	WBS ST Lbr	11901000	11901000	(35,199.72)
505000	Other Operating Exp	11901000	11920000	-
500000	Salaries and Wages	11901000	11903000	114,224.32
				114,224.32

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11902000	11902000	7,043.02
500010	Overtime	11902000	11902000	1,986.50
800000	Lbr Alloc	11902000	11902000	4,864.86
800000	Lbr Alloc	11902000	11902000	61,009.28
802000	Settle Lbr	11902000	11902000	(1,171.74)
802000	Settle Lbr	11902000	11902000	(58.04)
802000	Settle Lbr	11902000	11902000	9,748.80
804000	WBS ST Lbr	11902000	11902000	(79,787.60)
505000	Other Operating Exp	11902000	11920000	-
500000	Salaries and Wages	11902000	11920000	23,546.45
500000	Salaries and Wages	11902000	11920000	226,916.70
500000	Salaries and Wages	11902000	11902000	31,857.75
500010	Overtime	11902000	11902000	11,126.98
500050	AllocCorp Lbr Leg	11902000	11902000	(41,701.76)
500100	Vacation & Other TO	11902000	11902000	6,906.84
503300	Misc Other Deduction	11902000	11902000	150.78
803000	Assess Lbr	11902000	11902000	20,708.77
803050	Assess Fleet - Asses	11902000	11902000	1.50
803080	Assess Meals	11902000	11902000	265.43
803110	Assess OH Benefit	11902000	11902000	1,346.57
804000	WBS ST Lbr	11902000	11902000	243,729.78
804020	WBS ST Material	11902000	11902000	15,262.36
804030	WBS ST Services	11902000	11902000	12,903.99
804040	WBS ST Other	11902000	11902000	35,056.76
804050	WBS ST Fleet	11902000	11902000	40,904.44
804085	WBS ST Travel	11902000	11902000	61,956.51
804110	WBS ST OH Benefit	11902000	11902000	4,042.24
853000	Assess Lbr-Intrc	11902000	11902000	42,984.73
853110	As OH BenIntrc	11902000	11902000	(1,282.97)
500000	Salaries and Wages	11902000	11902000	(17,320.80)
500010	Overtime	11902000	11902000	3,021.61
500050	AllocCorp Lbr Leg	11902000	11902000	14,525.27

500100	Vacation & Other TO	11902000	11902000	10,818.90
500255	Service Awards	11902000	11902000	496.00
500300	Outside Svs	11902000	11902000	2,502.72
803000	Assess Lbr	11902000	11902000	3,482.42
803040	Assess Other	11902000	11902000	346.60
803110	Assess OH Benefit	11902000	11902000	162.43
804000	WBS ST Lbr	11902000	11902000	190,908.01
804020	WBS ST Material	11902000	11902000	3,438.02
804030	WBS ST Services	11902000	11902000	222.86
804040	WBS ST Other	11902000	11902000	1,427.59
853000	Assess Lbr-Intrc	11902000	11902000	(14,299.19)
853110	As OH BenIntrc	11902000	11902000	(226.08)
500000	Salaries and Wages	11902000	11902000	17,434.18
500010	Overtime	11902000	11902000	7,243.33
500050	AllocCorp Lbr Leg	11902000	11902000	(23,047.99)
500100	Vacation & Other TO	11902000	11902000	4,993.74
803000	Assess Lbr	11902000	11902000	12,517.32
803020	Assess Material	11902000	11902000	1,861.87
803040	Assess Other	11902000	11902000	664.61
803080	Assess Meals	11902000	11902000	1,393.75
804000	WBS ST Lbr	11902000	11902000	139,342.16
804020	WBS ST Material	11902000	11902000	7,492.24
804030	WBS ST Services	11902000	11902000	973.15
804040	WBS ST Other	11902000	11902000	210.35
853000	Assess Lbr-Intrc	11902000	11902000	24,677.51
853110	As OH BenIntrc	11902000	11902000	(1,629.52)
500000	Salaries and Wages	11902000	11902000	78.84
505000	Other Operating Exp	11902000	11902000	2,602.85
800000	Lbr Alloc	11902000	11902000	1,325.62
802000	Settle Lbr	11902000	11902000	342.88
804000	WBS ST Lbr	11902000	11902000	(1,747.34)
804040	WBS ST Other	11902000	11902000	(2,602.85)
500000	Salaries and Wages	11902000	11920000	2,553.16
				1,136,505.15

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11903000	11903000	32,298.84
500010	Overtime	11903000	11903000	3,604.61
500100	Vacation & Other TO	11903000	11903000	11,881.89
500300	Outside Svs	11903000	11903000	39,716.41
500300	Outside Svs	11903000	11903000	42,654.10
500300	Outside Svs	11903000	11903000	(42,654.10)
501500	Advertising Expenses	11903000	11903000	2,879.45
501500	Advertising Expenses	11903000	11903000	1,732.50

502400	Legal Expenses	11903000	11903000	95.25
505000	Other Operating Exp	11903000	11903000	156.72
505000	Other Operating Exp	11903000	11903000	11,016.46
505000	Other Operating Exp	11903000	11903000	(11,016.46)
702000	BS Lbr Offset	11903000	11903000	(1,304.66)
800000	Lbr Alloc	11903000	11903000	2,882.07
800000	Lbr Alloc	11903000	11903000	245,091.26
802000	Settle Lbr	11903000	11903000	(1,627.76)
802000	Settle Lbr	11903000	11903000	(19.71)
803000	Assess Lbr	11903000	11903000	1,304.66
804000	WBS ST Lbr	11903000	11903000	(280,994.71)
804030	WBS ST Services	11903000	11903000	(39,716.41)
804040	WBS ST Other	11903000	11903000	(11,563.62)
804110	WBS ST OH Benefit	11903000	11903000	(11,881.89)
505000	Other Operating Exp	11903000	11920000	-
500000	Salaries and Wages	11903000	11903000	945,710.99
500000	Salaries and Wages	11903000	11903000	27,872.83
500010	Overtime	11903000	11903000	19,204.80
500050	AllocCorp Lbr Leg	11903000	11903000	(41,589.94)
500060	AllocReg Lbr Leg	11903000	11903000	18,431.34
500100	Vacation & Other TO	11903000	11903000	(1,006.16)
500300	Outside Svs	11903000	11903000	939.59
505070	Cust Rec&Cltn Exp	11903000	11903000	686,879.59
505070	Cust Rec&Cltn Exp	11903000	11903000	180,210.98
505070	Cust Rec&Cltn Exp	11903000	11903000	259,461.22
505070	Cust Rec&Cltn Exp	11903000	11903000	(259,461.22)
505100	Cost Alloc to Cap	11903000	11903000	(142,874.75)
803000	Assess Lbr	11903000	11903000	(24,209.69)
803040	Assess Other	11903000	11903000	1,215.08
803080	Assess Meals	11903000	11903000	806.83
803085	Assess Travel	11903000	11903000	1,922.30
803110	Assess OH Benefit	11903000	11903000	145.92
804000	WBS ST Lbr	11903000	11903000	311,836.00
804030	WBS ST Services	11903000	11903000	61,902.74
804040	WBS ST Other	11903000	11903000	57,986.51
804050	WBS ST Fleet	11903000	11903000	27.03
804080	WBS ST Meals	11903000	11903000	284.62
804085	WBS ST Travel	11903000	11903000	371.83
853000	Assess Lbr-Intrc	11903000	11903000	47,077.63
853040	Assess Other-Intrc	11903000	11903000	18.86
853080	Assess Meals -Intrc	11903000	11903000	114.36
853110	As OH BenIntrc	11903000	11903000	(5,620.91)
505000	Other Operating Exp	11903000	11903000	(1,770.97)
505100	Cost Alloc to Cap	11903000	11903000	(2,109.23)

803000	Assess Lbr	11903000	11903000	(1,304.66)
804000	WBS ST Lbr	11903000	11903000	8,787.52
500000	Salaries and Wages	11903000	11920000	37,834.34
505070	Cust Rec&Cltn Exp	11903000	11920000	968.18
500300	Outside Svs	11903000	11903000	19.38
503110	Training	11903000	11903000	3,000.00
505070	Cust Rec&Cltn Exp	11903000	11903000	78.73
505070	Cust Rec&Cltn Exp	11903000	11903000	2,131.16
505070	Cust Rec&Cltn Exp	11903000	11903000	6,152.56
505070	Cust Rec&Cltn Exp	11903000	11903000	(6,152.56)
505070	Cust Rec&Cltn Exp	11903000	11920000	13,517.60
				2,203,345.33

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
502000	Bad Debt Write-off	11904000	11903000	1,073,428.98
502000	Bad Debt Write-off	11904000	11903000	55,347.60
502020	Bad Debt Manual Adj	11904000	11903000	(2,894,556.94)
502000	Bad Debt Write-off	11904000	11920000	(521,570.86)
502000	Bad Debt Write-off	11904000	11920000	(261,122.28)
502020	Bad Debt Manual Adj	11904000	11920000	375,087.20
502000	Bad Debt Write-off	11904000	11480000	(55,347.60)
502010	Bad Debt IVA	11904000	11480000	3,192,768.77
502000	Bad Debt Write-off	11904000	11903000	34,665.62
502000	Bad Debt Write-off	11904000	11903000	617.76
502020	Bad Debt Manual Adj	11904000	11903000	(134,394.20)
502020	Bad Debt Manual Adj	11904000	11920000	151,789.94
502000	Bad Debt Write-off	11904000	11480000	(617.76)
502010	Bad Debt IVA	11904000	11480000	137,339.22
				1,153,435.45

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
800000	Lbr Alloc	11905000	11905000	60,700.71
802000	Settle Lbr	11905000	11905000	(15,367.96)
802000	Settle Lbr	11905000	11905000	(338.48)
505000	Other Operating Exp	11905000	11920000	-
				44,994.27

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11909000	11903000	51,714.46
501500	Advertising Expenses	11909000	11903000	40,532.51
				92,246.97

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
702000	BS Lbr Offset	11912000	11912000	(27,008.88)

800000	Lbr Alloc	11912000	11912000	109,955.08
803000	Assess Lbr	11912000	11912000	27,008.88
804000	WBS ST Lbr	11912000	11912000	171.92
804000	WBS ST Lbr	11912000	11912000	(110,127.00)
505000	Other Operating Exp	11912000	11920000	-
500000	Salaries and Wages	11912000	11912000	308,255.15
500000	Salaries and Wages	11912000	11912000	11,384.15
500050	AllocCorp Lbr Leg	11912000	11912000	(9,994.28)
500100	Vacation & Other TO	11912000	11912000	7,862.62
501500	Advertising Expenses	11912000	11912000	(300.00)
505000	Other Operating Exp	11912000	11912000	(60,753.99)
505100	Cost Alloc to Cap	11912000	11912000	(72,358.00)
803000	Assess Lbr	11912000	11912000	(23,645.83)
803000	Assess Lbr	11912000	11912000	(27,008.88)
803085	Assess Travel	11912000	11912000	538.11
804000	WBS ST Lbr	11912000	11912000	124,582.05
853000	Assess Lbr-Intrc	11912000	11912000	10,642.16
853110	As OH BenIntrc	11912000	11912000	(647.88)
				268,555.38

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11913000	11913000	818.52
500300	Outside Svs	11913000	11913000	22,186.33
501500	Advertising Expenses	11913000	11913000	37,861.44
501500	Advertising Expenses	11913000	11913000	4,906.24
501500	Advertising Expenses	11913000	11913000	31,584.49
501500	Advertising Expenses	11913000	11913000	(30,145.99)
505000	Other Operating Exp	11913000	11913000	9,565.92
505000	Other Operating Exp	11913000	11913000	(9,565.92)
804000	WBS ST Lbr	11913000	11913000	(5,918.84)
804030	WBS ST Services	11913000	11913000	(22,186.33)
804040	WBS ST Other	11913000	11913000	(53,232.84)
804050	WBS ST Fleet	11913000	11913000	(27.03)
804080	WBS ST Meals	11913000	11913000	(284.62)
804085	WBS ST Travel	11913000	11913000	(371.83)
854000	WBS ST Lbr-Intrc	11913000	11913000	5,100.32
854040	WBS ST Other-Intrc	11913000	11913000	9,026.66
854050	WBS ST Fleet-Intrc	11913000	11913000	27.03
854080	WBS ST Meals-Intrc	11913000	11913000	284.62
854085	WBS ST Travel-Intrc	11913000	11913000	371.83
505000	Other Operating Exp	11913000	11920000	-
				0.00

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022

500000	Salaries and Wages	11916000	11912000	58,696.49
501500	Advertising Expenses	11916000	11912000	362.42
				59,058.91

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11920000	11920000	43,866.18
500010	Overtime	11920000	11920000	1,016.68
500100	Vacation & Other TO	11920000	11920000	1,060.53
500210	LTIP	11920000	11920000	23,360.00
500220	Bonuses	11920000	11920000	126,768.29
501220	Fleet-Repair/Main	11920000	11920000	133,084.49
501230	Fleet-Permit/Inspect	11920000	11920000	12,482.91
702000	BS Lbr Offset	11920000	11920000	(53,787.64)
702110	BS Ops OH Benefit	11920000	11920000	(150,128.29)
800000	Lbr Alloc	11920000	11920000	273,254.63
802000	Settle Lbr	11920000	11717000	(586.52)
802000	Settle Lbr	11920000	11874000	(29,343.21)
802000	Settle Lbr	11920000	11874000	(29.57)
802000	Settle Lbr	11920000	11878000	(143,306.43)
802000	Settle Lbr	11920000	11878000	(1,831.40)
802000	Settle Lbr	11920000	11879000	(16,568.07)
802000	Settle Lbr	11920000	11887000	(13,337.80)
802000	Settle Lbr	11920000	11887000	(1,360.82)
802000	Settle Lbr	11920000	11892000	(2,057.48)
802000	Settle Lbr	11920000	11902000	(3,331.62)
802000	Settle Lbr	11920000	11902000	(303.46)
802000	Settle Lbr	11920000	11903000	(1,234.60)
802000	Settle Lbr	11920000	11905000	(44,014.31)
802000	Settle Lbr	11920000	11905000	(979.96)
802020	Settle Material	11920000	11874000	(2,030.57)
802020	Settle Material	11920000	11878000	(798.56)
802020	Settle Material	11920000	11879000	(2,169.76)
802020	Settle Material	11920000	11892000	(125.17)
802030	Settle Services	11920000	11874000	(528.00)
802030	Settle Services	11920000	11887000	(806.02)
802040	Settle Other	11920000	11887000	-
803000	Assess Lbr	11920000	11920000	53,787.64
804000	WBS ST Lbr	11920000	11920000	42,827.32
804000	WBS ST Lbr	11920000	11920000	(341,437.09)
804030	WBS ST Services	11920000	11920000	(471.51)
804030	WBS ST Services	11920000	11920000	(43,817.34)
804040	WBS ST Other	11920000	11920000	(30,179.81)
804040	WBS ST Other	11920000	11920000	(159,495.90)
804050	WBS ST Fleet	11920000	11920000	(44,281.61)

804050	WBS ST Fleet	11920000	11920000	(101,285.79)
804085	WBS ST Travel	11920000	11920000	(67,071.78)
804085	WBS ST Travel	11920000	11920000	(377,811.12)
804110	WBS ST OH Benefit	11920000	11920000	37.44
804110	WBS ST OH Benefit	11920000	11920000	(1,138.66)
804112	WBS ST OH Payroll Tx	11920000	11920000	5.64
804112	WBS ST OH Payroll Tx	11920000	11920000	(5.64)
804113	WBS ST OH Pen/OPEB	11920000	11920000	5.76
804113	WBS ST OH Pen/OPEB	11920000	11920000	(7.06)
804114	WBS ST OH Prop Ins	11920000	11920000	3.24
804114	WBS ST OH Prop Ins	11920000	11920000	(9.16)
804116	WBS ST Vacation	11920000	11920000	8.79
854000	WBS ST Lbr-Intrc	11920000	11920000	48.06
854000	WBS ST Lbr-Intrc	11920000	11920000	69.52
854000	WBS ST Lbr-Intrc	11920000	11920000	17,987.69
854000	WBS ST Lbr-Intrc	11920000	11920000	(37,632.99)
854040	WBS ST Other-Intrc	11920000	11920000	8.37
854110	WBS ST OH Ben-Intrc	11920000	11920000	29.92
854113	WBS ST OH Pn/OPEB-in	11920000	11920000	1.30
854114	WBS ST OH PrIn-Intrc	11920000	11920000	5.92
854116	WBS ST Vaca-Intrc	11920000	11920000	1.98
500050	AllocCorp Lbr Leg	11920000	11920000	(458.52)
804030	WBS ST Services	11920000	11920000	3,500.00
804040	WBS ST Other	11920000	11920000	2,573.48
500000	Salaries and Wages	11920000	11920000	40,439.98
500000	Salaries and Wages	11920000	11920000	-
500060	AllocReg Lbr Leg	11920000	11920000	9,274.75
500060	AllocReg Lbr Leg	11920000	11920000	24,166.23
500100	Vacation & Other TO	11920000	11920000	(26,535.57)
803110	Assess OH Benefit	11920000	11920000	(2,906.69)
803112	Assess Payroll Tax	11920000	11920000	(356.40)
853000	Assess Lbr-Intrc	11920000	11920000	77,903.06
854000	WBS ST Lbr-Intrc	11920000	11920000	626.32
854000	WBS ST Lbr-Intrc	11920000	11920000	(65,507.34)
854040	WBS ST Other-Intrc	11920000	11920000	2,460.00
854110	WBS ST OH Ben-Intrc	11920000	11920000	253.67
803110	Assess OH Benefit	11920000	11920000	(2,649.72)
803112	Assess Payroll Tax	11920000	11920000	(148.56)
853000	Assess Lbr-Intrc	11920000	11920000	8,338.26
853000	Assess Lbr-Intrc	11920000	11920000	2,053.34
505210	AllocReg NonLbr Leg	11920000	11426000	(38,290.49)
500000	Salaries and Wages	11920000	11920000	173,347.36
500000	Salaries and Wages	11920000	11920000	1,428.94
500050	AllocCorp Lbr Leg	11920000	11920000	23.39

500050	AllocCorp Lbr Leg	11920000	11920000	(7,116.01)
500060	AllocReg Lbr Leg	11920000	11920000	45,420.67
500060	AllocReg Lbr Leg	11920000	11920000	1,158.02
500100	Vacation & Other TO	11920000	11920000	(30,880.58)
505000	Other Operating Exp	11920000	11920000	11,749.83
505000	Other Operating Exp	11920000	11920000	(11,749.83)
505000	Other Operating Exp	11920000	11920000	(1,464,605.23)
505000	Other Operating Exp	11920000	11920000	(943,283.93)
505000	Other Operating Exp	11920000	11920000	2,434,945.41
505100	Cost Alloc to Cap	11920000	11920000	(5,500.94)
803110	Assess OH Benefit	11920000	11920000	1,205.06
853000	Assess Lbr-Intrc	11920000	11920000	6,661.29
803110	Assess OH Benefit	11920000	11920000	(73,893.86)
803112	Assess Payroll Tax	11920000	11920000	(1,354.58)
853000	Assess Lbr-Intrc	11920000	11920000	45,494.38
853000	Assess Lbr-Intrc	11920000	11920000	65.81
853000	Assess Lbr-Intrc	11920000	11920000	86,070.65
853000	Assess Lbr-Intrc	11920000	11920000	(1,577.63)
854000	WBS ST Lbr-Intrc	11920000	11920000	9,276.79
854000	WBS ST Lbr-Intrc	11920000	11920000	(108,029.53)
854000	WBS ST Lbr-Intrc	11920000	11920000	37,632.99
854030	WBS ST Serv-Intrc	11920000	11920000	1,127.72
854030	WBS ST Serv-Intrc	11920000	11920000	2,800.00
854040	WBS ST Other-Intrc	11920000	11920000	1,775.00
854050	WBS ST Fleet-Intrc	11920000	11920000	15.03
854080	WBS ST Meals-Intrc	11920000	11920000	186.12
854085	WBS ST Travel-Intrc	11920000	11920000	114.40
854110	WBS ST OH Ben-Intrc	11920000	11920000	3,757.10
500000	Salaries and Wages	11920000	11920000	102,981.01
500000	Salaries and Wages	11920000	11920000	4,974.41
500050	AllocCorp Lbr Leg	11920000	11920000	2,127.50
500050	AllocCorp Lbr Leg	11920000	11920000	(4,974.42)
500060	AllocReg Lbr Leg	11920000	11920000	844.93
500060	AllocReg Lbr Leg	11920000	11920000	82.18
500100	Vacation & Other TO	11920000	11920000	(14,856.84)
505000	Other Operating Exp	11920000	11920000	111.21
505100	Cost Alloc to Cap	11920000	11920000	(6,735.08)
804000	WBS ST Lbr	11920000	11920000	27,464.60
804030	WBS ST Services	11920000	11920000	-
804040	WBS ST Other	11920000	11920000	6,951.67
853000	Assess Lbr-Intrc	11920000	11920000	4,974.42
803110	Assess OH Benefit	11920000	11920000	(16,710.29)
803112	Assess Payroll Tax	11920000	11920000	(803.33)
803113	Assess Pension/OPEB	11920000	11920000	(11.68)

803114	Assess Prop Ins	11920000	11920000	(6.57)
853000	Assess Lbr-Intrc	11920000	11920000	26,672.11
853000	Assess Lbr-Intrc	11920000	11920000	1,097.29
853000	Assess Lbr-Intrc	11920000	11920000	6,907.20
500000	Salaries and Wages	11920000	11920000	143,536.42
500000	Salaries and Wages	11920000	11920000	5,382.48
500050	AllocCorp Lbr Leg	11920000	11920000	2,754.39
500050	AllocCorp Lbr Leg	11920000	11920000	(5,396.13)
500060	AllocReg Lbr Leg	11920000	11920000	72,027.98
500060	AllocReg Lbr Leg	11920000	11920000	7,254.24
500100	Vacation & Other TO	11920000	11920000	(5,794.12)
500120	Unemp/Emp Insurance	11920000	11920000	655.13
500150	Medicare/Healthcare	11920000	11920000	1,072,152.23
500210	LTIP	11920000	11920000	73,083.72
500210	LTIP	11920000	11920000	16,824.83
500220	Bonuses	11920000	11920000	905,205.37
500220	Bonuses	11920000	11920000	368,249.41
505100	Cost Alloc to Cap	11920000	11920000	(125,415.43)
802040	Settle Other	11920000	11920000	(463,746.44)
802110	Settle OH Benefit	11920000	11920000	383,460.51
802112	Settle Payroll Tax	11920000	11920000	183,752.42
802113	Settle Pension/OPEB	11920000	11920000	(385,356.58)
802114	Settle Prop Ins	11920000	11920000	(134,379.43)
802116	Settle Vacation	11920000	11920000	(316,515.36)
804000	WBS ST Lbr	11920000	11920000	77,281.93
804030	WBS ST Services	11920000	11920000	2,668.37
804040	WBS ST Other	11920000	11920000	258.78
804110	WBS ST OH Benefit	11920000	11920000	11,486.61
853000	Assess Lbr-Intrc	11920000	11920000	5,382.48
803110	Assess OH Benefit	11920000	11920000	(2,581.89)
803112	Assess Payroll Tax	11920000	11920000	(453.55)
853000	Assess Lbr-Intrc	11920000	11920000	3,861.03
853000	Assess Lbr-Intrc	11920000	11920000	10,418.53
853000	Assess Lbr-Intrc	11920000	11920000	1,197.93
854000	WBS ST Lbr-Intrc	11920000	11920000	26,790.91
854030	WBS ST Serv-Intrc	11920000	11920000	644.10
854040	WBS ST Other-Intrc	11920000	11920000	26,909.63
500050	AllocCorp Lbr Leg	11920000	11920000	19,451.08
803110	Assess OH Benefit	11920000	11920000	(114,458.82)
803112	Assess Payroll Tax	11920000	11920000	(247.81)
853000	Assess Lbr-Intrc	11920000	11920000	24,716.64
853000	Assess Lbr-Intrc	11920000	11920000	420.02
854000	WBS ST Lbr-Intrc	11920000	11920000	2,962.28
854030	WBS ST Serv-Intrc	11920000	11920000	177,220.31

854110	WBS ST OH Ben-Intrc	11920000	11920000	1,199.73
854110	WBS ST OH Ben-Intrc	11920000	11920000	342,214.68
500000	Salaries and Wages	11920000	11880000	28,400.69
500050	AllocCorp Lbr Leg	11920000	11880000	10,434.52
803110	Assess OH Benefit	11920000	11920000	(1,303.09)
803112	Assess Payroll Tax	11920000	11920000	(35.56)
853000	Assess Lbr-Intrc	11920000	11920000	7,413.38
853000	Assess Lbr-Intrc	11920000	11920000	813.59
853020	As Mat -Intrc	11920000	11920000	753.71
853030	As Serv-Intrc	11920000	11920000	18,638.86
853040	Assess Other-Intrc	11920000	11920000	228.02
853040	Assess Other-Intrc	11920000	11920000	8.55
853080	Assess Meals -Intrc	11920000	11920000	82.81
853085	Assess Travel-Intrc	11920000	11920000	66.24
853110	As OH BenIntrc	11920000	11920000	3,745.98
853110	As OH BenIntrc	11920000	11920000	326.16
853112	As Prl Tx-Intrc	11920000	11920000	111.13
854030	WBS ST Serv-Intrc	11920000	11920000	8,988.55
500050	AllocCorp Lbr Leg	11920000	11920000	17,556.51
803110	Assess OH Benefit	11920000	11920000	(1,351.18)
803112	Assess Payroll Tax	11920000	11920000	(24.07)
853000	Assess Lbr-Intrc	11920000	11920000	(9,733.80)
854000	WBS ST Lbr-Intrc	11920000	11920000	8,651.64
854110	WBS ST OH Ben-Intrc	11920000	11920000	3,503.91
803110	Assess OH Benefit	11920000	11920000	(1,103.50)
803112	Assess Payroll Tax	11920000	11920000	(293.72)
853000	Assess Lbr-Intrc	11920000	11920000	501.87
853000	Assess Lbr-Intrc	11920000	11920000	2,384.90
854000	WBS ST Lbr-Intrc	11920000	11920000	12,131.73
500000	Salaries and Wages	11920000	11920000	22,244.39
500000	Salaries and Wages	11920000	11920000	-
500050	AllocCorp Lbr Leg	11920000	11920000	78,054.01
500050	AllocCorp Lbr Leg	11920000	11920000	6,836.61
500100	Vacation & Other TO	11920000	11920000	(8,699.60)
803110	Assess OH Benefit	11920000	11920000	(18,528.04)
803112	Assess Payroll Tax	11920000	11920000	(2,082.89)
853000	Assess Lbr-Intrc	11920000	11920000	181.44
853000	Assess Lbr-Intrc	11920000	11920000	37,110.98
853000	Assess Lbr-Intrc	11920000	11920000	17,931.49
854000	WBS ST Lbr-Intrc	11920000	11920000	315.86
854000	WBS ST Lbr-Intrc	11920000	11920000	18,019.21
854030	WBS ST Serv-Intrc	11920000	11920000	61,339.49
854030	WBS ST Serv-Intrc	11920000	11920000	178,066.99
854040	WBS ST Other-Intrc	11920000	11920000	415,857.65

854040	WBS ST Other-Intrc	11920000	11920000	3,475.55
854110	WBS ST OH Ben-Intrc	11920000	11920000	127.93
854110	WBS ST OH Ben-Intrc	11920000	11920000	9,910.56
500050	AllocCorp Lbr Leg	11920000	11920000	10,009.92
802110	Settle OH Benefit	11920000	11920000	(322,980.52)
804030	WBS ST Services	11920000	11920000	2,940.00
804040	WBS ST Other	11920000	11920000	66,952.68
803110	Assess OH Benefit	11920000	11920000	(9,706.89)
803112	Assess Payroll Tax	11920000	11920000	(962.57)
853000	Assess Lbr-Intrc	11920000	11920000	6,575.46
853000	Assess Lbr-Intrc	11920000	11920000	15,472.97
854000	WBS ST Lbr-Intrc	11920000	11920000	4,497.14
854110	WBS ST OH Ben-Intrc	11920000	11920000	1,821.35
803110	Assess OH Benefit	11920000	11920000	(1,074.83)
803112	Assess Payroll Tax	11920000	11920000	(307.09)
853000	Assess Lbr-Intrc	11920000	11920000	3,820.16
853000	Assess Lbr-Intrc	11920000	11920000	(5,797.37)
803110	Assess OH Benefit	11920000	11920000	(652.34)
803112	Assess Payroll Tax	11920000	11920000	(195.29)
853000	Assess Lbr-Intrc	11920000	11920000	2,096.19
853000	Assess Lbr-Intrc	11920000	11920000	(1,369.76)
500050	AllocCorp Lbr Leg	11920000	11920000	363.85
505100	Cost Alloc to Cap	11920000	11920000	(15,301.47)
505100	Cost Alloc to Cap	11920000	11920000	(17,655.54)
803110	Assess OH Benefit	11920000	11920000	(1,212.30)
803112	Assess Payroll Tax	11920000	11920000	(438.62)
853000	Assess Lbr-Intrc	11920000	11920000	1,191.91
853000	Assess Lbr-Intrc	11920000	11920000	1,298.06
505100	Cost Alloc to Cap	11920000	11920000	(8,145.76)
505100	Cost Alloc to Cap	11920000	11920000	(24,029.99)
803110	Assess OH Benefit	11920000	11920000	(2,804.49)
803112	Assess Payroll Tax	11920000	11920000	(910.56)
853000	Assess Lbr-Intrc	11920000	11920000	5,981.73
853000	Assess Lbr-Intrc	11920000	11920000	(4,581.45)
500000	Salaries and Wages	11920000	11920000	150,189.49
500000	Salaries and Wages	11920000	11920000	15,256.65
500050	AllocCorp Lbr Leg	11920000	11920000	100,672.53
500050	AllocCorp Lbr Leg	11920000	11920000	(15,256.66)
500060	AllocReg Lbr Leg	11920000	11920000	189,530.73
500060	AllocReg Lbr Leg	11920000	11920000	12,320.18
500100	Vacation & Other TO	11920000	11920000	(1,280.84)
500150	Medicare/Healthcare	11920000	11920000	636,246.35
505100	Cost Alloc to Cap	11920000	11920000	(29,750.94)
803110	Assess OH Benefit	11920000	11920000	682.18

804000	WBS ST Lbr	11920000	11920000	28,971.93
804030	WBS ST Services	11920000	11920000	152,686.07
804040	WBS ST Other	11920000	11920000	120,840.95
804110	WBS ST OH Benefit	11920000	11920000	31.90
804113	WBS ST OH Pen/OPEB	11920000	11920000	1.30
804114	WBS ST OH Prop Ins	11920000	11920000	5.92
853000	Assess Lbr-Intrc	11920000	11920000	15,256.66
803110	Assess OH Benefit	11920000	11920000	(25,010.90)
803112	Assess Payroll Tax	11920000	11920000	(4,449.11)
853000	Assess Lbr-Intrc	11920000	11920000	44,654.66
853000	Assess Lbr-Intrc	11920000	11920000	104,799.09
853000	Assess Lbr-Intrc	11920000	11920000	9,003.54
854000	WBS ST Lbr-Intrc	11920000	11920000	17,081.93
854000	WBS ST Lbr-Intrc	11920000	11920000	(238,330.30)
854030	WBS ST Serv-Intrc	11920000	11920000	234.65
854040	WBS ST Other-Intrc	11920000	11920000	42,472.50
854110	WBS ST OH Ben-Intrc	11920000	11920000	6,918.19
803110	Assess OH Benefit	11920000	11920000	(709.67)
803112	Assess Payroll Tax	11920000	11920000	(11.81)
853000	Assess Lbr-Intrc	11920000	11920000	(579.43)
500050	AllocCorp Lbr Leg	11920000	11920000	22,735.52
803110	Assess OH Benefit	11920000	11920000	(4,423.04)
803112	Assess Payroll Tax	11920000	11920000	(574.04)
853000	Assess Lbr-Intrc	11920000	11920000	29,642.07
854000	WBS ST Lbr-Intrc	11920000	11920000	8,671.56
854110	WBS ST OH Ben-Intrc	11920000	11920000	3,511.98
500050	AllocCorp Lbr Leg	11920000	11920000	51,392.49
505100	Cost Alloc to Cap	11920000	11920000	(17,795.40)
803110	Assess OH Benefit	11920000	11920000	(5,303.40)
803112	Assess Payroll Tax	11920000	11920000	(137.51)
853000	Assess Lbr-Intrc	11920000	11920000	7,489.50
853000	Assess Lbr-Intrc	11920000	11920000	1,086.05
854000	WBS ST Lbr-Intrc	11920000	11920000	25,917.07
854110	WBS ST OH Ben-Intrc	11920000	11920000	10,496.40
803110	Assess OH Benefit	11920000	11920000	(973.74)
803112	Assess Payroll Tax	11920000	11920000	(106.76)
853000	Assess Lbr-Intrc	11920000	11920000	10,689.18
853000	Assess Lbr-Intrc	11920000	11920000	1,890.61
803110	Assess OH Benefit	11920000	11920000	(1,808.89)
803112	Assess Payroll Tax	11920000	11920000	(119.45)
853000	Assess Lbr-Intrc	11920000	11920000	1,812.74
853000	Assess Lbr-Intrc	11920000	11920000	4,062.30
854000	WBS ST Lbr-Intrc	11920000	11920000	1,312.64
854110	WBS ST OH Ben-Intrc	11920000	11920000	721.96

500050	AllocCorp Lbr Leg	11920000	11920000	12,750.88
803110	Assess OH Benefit	11920000	11920000	(1,934.16)
803112	Assess Payroll Tax	11920000	11920000	(58.83)
853000	Assess Lbr-Intrc	11920000	11920000	2,517.01
853000	Assess Lbr-Intrc	11920000	11920000	2,981.00
854000	WBS ST Lbr-Intrc	11920000	11920000	1,175.58
854110	WBS ST OH Ben-Intrc	11920000	11920000	646.57
803110	Assess OH Benefit	11920000	11920000	(1,581.46)
803112	Assess Payroll Tax	11920000	11920000	(39.65)
853000	Assess Lbr-Intrc	11920000	11920000	2,528.20
853000	Assess Lbr-Intrc	11920000	11920000	2,237.89
803110	Assess OH Benefit	11920000	11920000	(4,275.28)
803112	Assess Payroll Tax	11920000	11920000	(387.37)
853000	Assess Lbr-Intrc	11920000	11920000	3,767.74
853000	Assess Lbr-Intrc	11920000	11920000	5,821.95
500000	Salaries and Wages	11920000	11920000	152,352.41
500000	Salaries and Wages	11920000	11920000	6,749.40
500050	AllocCorp Lbr Leg	11920000	11920000	12,584.01
500050	AllocCorp Lbr Leg	11920000	11920000	(6,007.02)
500060	AllocReg Lbr Leg	11920000	11920000	2,473.67
500100	Vacation & Other TO	11920000	11920000	(11,672.72)
505100	Cost Alloc to Cap	11920000	11920000	(15,557.50)
804000	WBS ST Lbr	11920000	11920000	73,155.78
804030	WBS ST Services	11920000	11920000	26,771.75
804040	WBS ST Other	11920000	11920000	16,077.46
804110	WBS ST OH Benefit	11920000	11920000	1,060.53
853000	Assess Lbr-Intrc	11920000	11920000	6,749.39
803110	Assess OH Benefit	11920000	11920000	(5,695.92)
803112	Assess Payroll Tax	11920000	11920000	(324.08)
853000	Assess Lbr-Intrc	11920000	11920000	7,307.74
853000	Assess Lbr-Intrc	11920000	11920000	33,250.02
853000	Assess Lbr-Intrc	11920000	11920000	7,786.05
854000	WBS ST Lbr-Intrc	11920000	11920000	(45,294.29)
854000	WBS ST Lbr-Intrc	11920000	11920000	480.67
854030	WBS ST Serv-Intrc	11920000	11920000	23,689.82
854110	WBS ST OH Ben-Intrc	11920000	11920000	264.37
500050	AllocCorp Lbr Leg	11920000	11920000	53,324.37
500050	AllocCorp Lbr Leg	11920000	11920000	6,587.90
803110	Assess OH Benefit	11920000	11920000	(9,447.75)
803112	Assess Payroll Tax	11920000	11920000	(529.07)
853000	Assess Lbr-Intrc	11920000	11920000	13,303.30
853000	Assess Lbr-Intrc	11920000	11920000	8,448.36
853000	Assess Lbr-Intrc	11920000	11920000	114.60
854000	WBS ST Lbr-Intrc	11920000	11920000	18,491.49

854110	WBS ST OH Ben-Intrc	11920000	11920000	10,170.31
500050	AllocCorp Lbr Leg	11920000	11920000	414.28
803110	Assess OH Benefit	11920000	11920000	(809.62)
803112	Assess Payroll Tax	11920000	11920000	(70.55)
853000	Assess Lbr-Intrc	11920000	11920000	2,529.05
853000	Assess Lbr-Intrc	11920000	11920000	1,174.09
854000	WBS ST Lbr-Intrc	11920000	11920000	153.84
854030	WBS ST Serv-Intrc	11920000	11920000	12,811.42
854040	WBS ST Other-Intrc	11920000	11920000	53,375.00
854110	WBS ST OH Ben-Intrc	11920000	11920000	84.62
500000	Salaries and Wages	11920000	11920000	257,106.39
500000	Salaries and Wages	11920000	11920000	16,505.46
500050	AllocCorp Lbr Leg	11920000	11920000	32,798.61
500050	AllocCorp Lbr Leg	11920000	11920000	(18,475.74)
500100	Vacation & Other TO	11920000	11920000	1,962.91
503300	Misc Other Deduction	11920000	11920000	1,008.00
505100	Cost Alloc to Cap	11920000	11920000	(7,770.38)
804000	WBS ST Lbr	11920000	11920000	88,903.73
853000	Assess Lbr-Intrc	11920000	11920000	16,505.46
803110	Assess OH Benefit	11920000	11920000	(3,439.95)
803112	Assess Payroll Tax	11920000	11920000	(450.09)
853000	Assess Lbr-Intrc	11920000	11920000	2,892.41
853000	Assess Lbr-Intrc	11920000	11920000	27,953.41
854000	WBS ST Lbr-Intrc	11920000	11920000	(22,710.37)
854000	WBS ST Lbr-Intrc	11920000	11920000	543.48
854030	WBS ST Serv-Intrc	11920000	11920000	10,934.83
854030	WBS ST Serv-Intrc	11920000	11920000	3,384.14
803110	Assess OH Benefit	11920000	11920000	(1,446.54)
803112	Assess Payroll Tax	11920000	11920000	(36.67)
853000	Assess Lbr-Intrc	11920000	11920000	3,533.74
853000	Assess Lbr-Intrc	11920000	11920000	1,083.11
500000	Salaries and Wages	11920000	11903000	8,261.97
500050	AllocCorp Lbr Leg	11920000	11903000	45,940.06
500060	AllocReg Lbr Leg	11920000	11903000	49,914.64
505210	AllocReg NonLbr Leg	11920000	11903000	4,754.62
803110	Assess OH Benefit	11920000	11920000	(14,406.06)
803112	Assess Payroll Tax	11920000	11920000	(2,264.22)
803113	Assess Pension/OPEB	11920000	11920000	(1,958.72)
803114	Assess Prop Ins	11920000	11920000	(48.98)
853000	Assess Lbr-Intrc	11920000	11920000	(33,324.73)
853000	Assess Lbr-Intrc	11920000	11920000	41,334.74
854000	WBS ST Lbr-Intrc	11920000	11920000	5,138.75
854000	WBS ST Lbr-Intrc	11920000	11920000	(7,671.51)
854000	WBS ST Lbr-Intrc	11920000	11920000	286.96

854000	WBS ST Lbr-Intrc	11920000	11920000	2,945.87
854000	WBS ST Lbr-Intrc	11920000	11920000	28,511.91
854020	WBS ST Mat-Intrc	11920000	11920000	687.55
854030	WBS ST Serv-Intrc	11920000	11920000	197,639.83
854040	WBS ST Other-Intrc	11920000	11920000	5,137.96
854040	WBS ST Other-Intrc	11920000	11920000	2,198.14
854110	WBS ST OH Ben-Intrc	11920000	11920000	2,081.18
854110	WBS ST OH Ben-Intrc	11920000	11920000	1,091.38
854110	WBS ST OH Ben-Intrc	11920000	11920000	936.20
854110	WBS ST OH Ben-Intrc	11920000	11920000	8,383.54
854112	WBS ST OH PrlTx-intr	11920000	11920000	216.57
854112	WBS ST OH PrlTx-intr	11920000	11920000	270.72
854112	WBS ST OH PrlTx-intr	11920000	11920000	2,340.83
854113	WBS ST OH Pn/OPEB-in	11920000	11920000	(39.83)
854113	WBS ST OH Pn/OPEB-in	11920000	11920000	(49.78)
854113	WBS ST OH Pn/OPEB-in	11920000	11920000	5,220.54
854114	WBS ST OH PrIn-Intrc	11920000	11920000	195.61
854114	WBS ST OH PrIn-Intrc	11920000	11920000	244.51
854116	WBS ST Vaca-Intrc	11920000	11920000	428.04
854116	WBS ST Vaca-Intrc	11920000	11920000	3,991.66
803110	Assess OH Benefit	11920000	11920000	(948.70)
803112	Assess Payroll Tax	11920000	11920000	(152.21)
853000	Assess Lbr-Intrc	11920000	11920000	(1,437.62)
853040	Assess Other-Intrc	11920000	11920000	20.00
853110	As OH BenIntrc	11920000	11920000	2,964.69
853112	As Prl Tx-Intrc	11920000	11920000	475.62
854000	WBS ST Lbr-Intrc	11920000	11920000	(4,757.71)
500000	Salaries and Wages	11920000	11920000	7,734.44
500050	AllocCorp Lbr Leg	11920000	11920000	(7,734.44)
500100	Vacation & Other TO	11920000	11920000	6,087.41
505100	Cost Alloc to Cap	11920000	11920000	(6,706.65)
853000	Assess Lbr-Intrc	11920000	11920000	7,734.44
500000	Salaries and Wages	11920000	11920000	879.80
505100	Cost Alloc to Cap	11920000	11920000	(25,122.16)
505210	AllocReg NonLbr Leg	11920000	11920000	11,032.71
803110	Assess OH Benefit	11920000	11920000	(161.91)
803112	Assess Payroll Tax	11920000	11920000	(67.61)
853000	Assess Lbr-Intrc	11920000	11920000	151.46
854000	WBS ST Lbr-Intrc	11920000	11920000	879.80
803110	Assess OH Benefit	11920000	11920000	(1,871.42)
803112	Assess Payroll Tax	11920000	11920000	(207.81)
853000	Assess Lbr-Intrc	11920000	11920000	8,885.20
854000	WBS ST Lbr-Intrc	11920000	11920000	578.88
500000	Salaries and Wages	11920000	11920000	48,588.46

500000	Salaries and Wages	11920000	11920000	22,426.97
500010	Overtime	11920000	11920000	3,354.88
500050	AllocCorp Lbr Leg	11920000	11920000	(23,007.54)
500060	AllocReg Lbr Leg	11920000	11920000	10,287.93
500060	AllocReg Lbr Leg	11920000	11920000	3,230.64
500100	Vacation & Other TO	11920000	11920000	(8,047.10)
502540	Prof Svs-Other	11920000	11920000	14,904.61
503200	Dues & Memberships	11920000	11920000	698.65
505100	Cost Alloc to Cap	11920000	11920000	(160,232.42)
804000	WBS ST Lbr	11920000	11920000	286,261.49
804020	WBS ST Material	11920000	11920000	89.94
804030	WBS ST Services	11920000	11920000	54,116.24
804040	WBS ST Other	11920000	11920000	166,553.45
804050	WBS ST Fleet	11920000	11920000	7,310.33
804085	WBS ST Travel	11920000	11920000	10,958.14
804110	WBS ST OH Benefit	11920000	11920000	485.88
853000	Assess Lbr-Intrc	11920000	11920000	25,781.85
803110	Assess OH Benefit	11920000	11920000	(4,967.16)
803112	Assess Payroll Tax	11920000	11920000	(1,120.19)
853000	Assess Lbr-Intrc	11920000	11920000	(2,323.60)
853000	Assess Lbr-Intrc	11920000	11920000	46,085.81
853000	Assess Lbr-Intrc	11920000	11920000	4,874.31
854000	WBS ST Lbr-Intrc	11920000	11920000	72.13
854000	WBS ST Lbr-Intrc	11920000	11920000	(31,033.59)
854110	WBS ST OH Ben-Intrc	11920000	11920000	29.21
853020	As Mat -Intrc	11920000	11920000	1,968.15
853030	As Serv-Intrc	11920000	11920000	6,563.23
853040	Assess Other-Intrc	11920000	11920000	34,261.47
853040	Assess Other-Intrc	11920000	11920000	118.65
500000	Salaries and Wages	11920000	11920000	114,230.03
500000	Salaries and Wages	11920000	11920000	(34,524.40)
500050	AllocCorp Lbr Leg	11920000	11920000	(2,839,496.74)
500100	Vacation & Other TO	11920000	11920000	(164,641.57)
500120	Unemp/Emp Insurance	11920000	11920000	(206.63)
502540	Prof Svs-Other	11920000	11920000	-
503300	Misc Other Deduction	11920000	11920000	(10,703.46)
505000	Other Operating Exp	11920000	11920000	(361.14)
505100	Cost Alloc to Cap	11920000	11920000	500.00
505210	AllocReg NonLbr Leg	11920000	11920000	9,118.34
505500	Collection System	11920000	11920000	(81.56)
505500	Collection System	11920000	11920000	81.56
590010	Current SIT Exp	11920000	11920000	60,000.00
590010	Current SIT Exp	11920000	11920000	(60,000.00)
590210	Deferred FIT Exp	11920000	11920000	(505,882.00)

590210	Deferred FIT Exp	11920000	11920000	505,882.00
590230	Deferred Amrt EADIT	11920000	11920000	-
803110	Assess OH Benefit	11920000	11920000	(281.74)
500000	Salaries and Wages	11920000	11920000	6,255.67
500010	Overtime	11920000	11920000	17,976.37
500050	AllocCorp Lbr Leg	11920000	11920000	(22,210.80)
500100	Vacation & Other TO	11920000	11920000	5,023.87
853000	Assess Lbr-Intrc	11920000	11920000	24,232.04
505200	AllocCorp NonLbr Leg	11920000	11920000	(9,051.07)
803110	Assess OH Benefit	11920000	11920000	(7,092.65)
803112	Assess Payroll Tax	11920000	11920000	(411.07)
803113	Assess Pension/OPEB	11920000	11920000	(25.37)
853000	Assess Lbr-Intrc	11920000	11920000	11,962.90
853000	Assess Lbr-Intrc	11920000	11920000	(586.29)
853000	Assess Lbr-Intrc	11920000	11920000	26,030.04
854000	WBS ST Lbr-Intrc	11920000	11920000	61.34
854000	WBS ST Lbr-Intrc	11920000	11920000	(53,589.18)
854030	WBS ST Serv-Intrc	11920000	11920000	15,432.93
854110	WBS ST OH Ben-Intrc	11920000	11920000	24.85
854110	WBS ST OH Ben-Intrc	11920000	11920000	187.56
854112	WBS ST OH PrlTx-intr	11920000	11920000	35.54
854113	WBS ST OH Pn/OPEB-in	11920000	11920000	79.26
804000	WBS ST Lbr	11920000	11920000	17,987.69
804030	WBS ST Services	11920000	11920000	340.00
804040	WBS ST Other	11920000	11920000	12,286,098.19
500000	Salaries and Wages	11920000	11920000	348.11
500000	Salaries and Wages	11920000	11920000	20,141.09
500060	AllocReg Lbr Leg	11920000	11920000	1,684.25
505100	Cost Alloc to Cap	11920000	11920000	(152,713.41)
505210	AllocReg NonLbr Leg	11920000	11920000	203,935.50
803110	Assess OH Benefit	11920000	11920000	(5,280.17)
803112	Assess Payroll Tax	11920000	11920000	(1,121.42)
853000	Assess Lbr-Intrc	11920000	11920000	23,750.98
854000	WBS ST Lbr-Intrc	11920000	11920000	63.53
854000	WBS ST Lbr-Intrc	11920000	11920000	81,113.11
854110	WBS ST OH Ben-Intrc	11920000	11920000	25.73
500000	Salaries and Wages	11920000	11871000	12,460.16
505210	AllocReg NonLbr Leg	11920000	11871000	219,353.98
803110	Assess OH Benefit	11920000	11920000	(6,397.61)
803112	Assess Payroll Tax	11920000	11920000	(1,312.22)
853000	Assess Lbr-Intrc	11920000	11920000	(7,261.97)
853040	Assess Other-Intrc	11920000	11920000	192.89
853080	Assess Meals -Intrc	11920000	11920000	101.28
853085	Assess Travel-Intrc	11920000	11920000	506.58

853110	As OH BenIntrc	11920000	11920000	19,992.54
853112	As Prl Tx-Intrc	11920000	11920000	4,100.65
854000	WBS ST Lbr-Intrc	11920000	11920000	122,762.15
500000	Salaries and Wages	11920000	11920000	20,123.43
500050	AllocCorp Lbr Leg	11920000	11920000	(19,940.35)
500100	Vacation & Other TO	11920000	11920000	7,007.36
804000	WBS ST Lbr	11920000	11920000	12,386.12
853000	Assess Lbr-Intrc	11920000	11920000	20,123.42
501760	Lic/Fee/Per-Escrow	11920000	11920000	(670.00)
500000	Salaries and Wages	11920000	11920000	(272,755.21)
500050	AllocCorp Lbr Leg	11920000	11920000	115,649.41
500100	Vacation & Other TO	11920000	11920000	666.70
500110	SS/CPP/Emp Pension	11920000	11920000	408.49
500170	Group/Emp Ben	11920000	11920000	22,847.49
505000	Other Operating Exp	11920000	11920000	2,204,125.91
505000	Other Operating Exp	11920000	11920000	(2,204,125.91)
505000	Other Operating Exp	11920000	11920000	(2,271,197.69)
505000	Other Operating Exp	11920000	11920000	2,271,197.69
803110	Assess OH Benefit	11920000	11920000	20,779.77
803110	Assess OH Benefit	11920000	11920000	53,415.07
803112	Assess Payroll Tax	11920000	11920000	2,583.39
803112	Assess Payroll Tax	11920000	11920000	(208.90)
803113	Assess Pension/OPEB	11920000	11920000	3,055.13
803113	Assess Pension/OPEB	11920000	11920000	(202.31)
803114	Assess Prop Ins	11920000	11920000	1,570.05
853000	Assess Lbr-Intrc	11920000	11920000	6,627.31
853000	Assess Lbr-Intrc	11920000	11920000	(275,564.33)
853000	Assess Lbr-Intrc	11920000	11920000	(272,755.21)
854000	WBS ST Lbr-Intrc	11920000	11920000	1,222.01
854030	WBS ST Serv-Intrc	11920000	11920000	23,397.70
854040	WBS ST Other-Intrc	11920000	11920000	93.08
854110	WBS ST OH Ben-Intrc	11920000	11920000	358.41
854112	WBS ST OH PrlTx-intr	11920000	11920000	100.32
854113	WBS ST OH Pn/OPEB-in	11920000	11920000	223.75
854116	WBS ST Vaca-Intrc	11920000	11920000	171.08
500120	Unemp/Emp Insurance	11920000	11920000	19.26
500000	Salaries and Wages	11920000	11920000	182,265.40
500000	Salaries and Wages	11920000	11920000	674.64
804000	WBS ST Lbr	11920000	11920000	234,064.96
804020	WBS ST Material	11920000	11920000	20,021.72
804030	WBS ST Services	11920000	11920000	40,701.48
804040	WBS ST Other	11920000	11920000	307,988.90
804110	WBS ST OH Benefit	11920000	11920000	1,329.95
502310	Facility Costs-Maint	11920000	11920000	404.74

502310	Facility Costs-Maint	11920000	11920000	370.97
804040	WBS ST Other	11920000	11920000	19,673.97
				15,957,477.35

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11921000	11921000	14,209.45
500300	Outside Svs	11921000	11921000	71,894.81
500300	Outside Svs	11921000	11921000	7,316.45
500400	Materials & Supplies	11921000	11199999	15,988.33
500400	Materials & Supplies	11921000	11874000	3,036.44
500400	Materials & Supplies	11921000	11874000	11,717.22
500400	Materials & Supplies	11921000	11878000	798.56
500400	Materials & Supplies	11921000	11878000	2,652.63
500400	Materials & Supplies	11921000	11879000	2,169.76
500400	Materials & Supplies	11921000	11879000	2,198.71
500400	Materials & Supplies	11921000	11887000	98.65
500400	Materials & Supplies	11921000	11887000	4,303.52
500400	Materials & Supplies	11921000	11892000	125.17
500400	Materials & Supplies	11921000	11892000	3,867.10
500400	Materials & Supplies	11921000	11893000	2,233.67
500400	Materials & Supplies	11921000	11894000	1,390.79
500400	Materials & Supplies	11921000	11921000	41.75
500405	M&C-NonStck Cntrl	11921000	11742000	1.00
500405	M&C-NonStck Cntrl	11921000	11742000	7,253.44
500405	M&C-NonStck Cntrl	11921000	11874000	30.00
500405	M&C-NonStck Cntrl	11921000	11874000	5,451.38
500405	M&C-NonStck Cntrl	11921000	11878000	(700.00)
500405	M&C-NonStck Cntrl	11921000	11878000	3,996.36
500405	M&C-NonStck Cntrl	11921000	11880000	(48.78)
500405	M&C-NonStck Cntrl	11921000	11880000	6,998.93
500405	M&C-NonStck Cntrl	11921000	11887000	1,140.00
500405	M&C-NonStck Cntrl	11921000	11892000	173.37
500405	M&C-NonStck Cntrl	11921000	11894000	57.80
500405	M&C-NonStck Cntrl	11921000	11894000	9,090.17
500405	M&C-NonStck Cntrl	11921000	11921000	14,387.10
500410	M&C-Small Tools	11921000	11742000	106.23
500410	M&C-Small Tools	11921000	11880000	1,243.43
500410	M&C-Small Tools	11921000	11894000	224.13
500410	M&C-Small Tools	11921000	11894000	43.12
500410	M&C-Small Tools	11921000	11894000	18,101.59
500420	M&C-Safety Supplies	11921000	11880000	14,119.34
500420	M&C-Safety Supplies	11921000	11893000	38.76
500430	M&C-Main Parts	11921000	11880000	80.96
500440	M&C-Spare Parts	11921000	11710000	1,211.73

500440	M&C-Spare Parts	11921000	11742000	2,041.36
500440	M&C-Spare Parts	11921000	11742000	1,405.70
500440	M&C-Spare Parts	11921000	11880000	715.50
500440	M&C-Spare Parts	11921000	11887000	3,381.85
500440	M&C-Spare Parts	11921000	11893000	187.11
500440	M&C-Spare Parts	11921000	11894000	748.82
500440	M&C-Spare Parts	11921000	11921000	159.45
500900	Util Exp-Water & Sew	11921000	11735000	1,173.03
500920	Util Exp-Heat & Elec	11921000	11735000	(120.07)
500920	Util Exp-Heat & Elec	11921000	11735000	58,022.73
500920	Util Exp-Heat & Elec	11921000	11874000	(33.34)
500920	Util Exp-Heat & Elec	11921000	11874000	2,441.64
500920	Util Exp-Heat & Elec	11921000	11880000	1,460.38
500940	Util Exp-Gas	11921000	11735000	1,076.61
500940	Util Exp-Gas	11921000	11880000	254.55
501130	Trvl Exp-Rental	11921000	11920000	444,882.90
501300	Meals & Ent	11921000	11921000	291.57
501400	Comm Exp-Telephone	11921000	11921000	28,053.41
501410	Comm Exp-Cellular	11921000	11921000	184.15
502100	Comp Exp	11921000	11921000	569.68
502110	Comp Exp-Repair	11921000	11107000	32,760.00
502110	Comp Exp-Repair	11921000	11163000	1,014.43
502110	Comp Exp-Repair	11921000	11921000	38,145.44
502700	Office Related Exp	11921000	11735000	3,013.62
502700	Office Related Exp	11921000	11742000	239.96
502700	Office Related Exp	11921000	11844000	2,472.23
502700	Office Related Exp	11921000	11874000	41.70
502700	Office Related Exp	11921000	11879000	1,166.05
502700	Office Related Exp	11921000	11880000	924.54
502700	Office Related Exp	11921000	11886000	10,369.80
502700	Office Related Exp	11921000	11893000	101.15
502700	Office Related Exp	11921000	11894000	115.20
502700	Office Related Exp	11921000	11920000	258.78
502700	Office Related Exp	11921000	11920000	288.33
502700	Office Related Exp	11921000	11921000	3,926.39
502710	Postage	11921000	11921000	20.64
503110	Training	11921000	11921000	9,082.90
505000	Other Operating Exp	11921000	11921000	274.10
505000	Other Operating Exp	11921000	11921000	11,579.36
505000	Other Operating Exp	11921000	11921000	16,963.59
505000	Other Operating Exp	11921000	11921000	(11,048.59)
800000	Lbr Alloc	11921000	11921000	18,861.57
804000	WBS ST Lbr	11921000	11921000	(33,071.02)
804020	WBS ST Material	11921000	11921000	(14,588.30)

804030	WBS ST Services	11921000	11921000	(76,411.26)
804040	WBS ST Other	11921000	11921000	(97,751.07)
804080	WBS ST Meals	11921000	11921000	(291.57)
854030	WBS ST Serv-Intrc	11921000	11921000	(2,800.00)
501140	Trvl Exp-Mileage	11921000	11920000	458.52
853085	Assess Travel-Intrc	11921000	11920000	458.52
853040	Assess Other-Intrc	11921000	11920000	737.54
853050	As Fleet - Intrc	11921000	11920000	58.06
853080	Assess Meals -Intrc	11921000	11920000	112.06
853085	Assess Travel-Intrc	11921000	11920000	1,744.25
501100	Trvl Exp	11921000	11920000	1,925.42
502700	Office Related Exp	11921000	11920000	245.98
502710	Postage	11921000	11920000	10.70
503200	Dues & Memberships	11921000	11920000	18,857.50
853040	Assess Other-Intrc	11921000	11920000	4,936.25
853040	Assess Other-Intrc	11921000	11920000	(102,800.25)
853050	As Fleet - Intrc	11921000	11920000	3.38
853050	As Fleet - Intrc	11921000	11920000	2.44
853080	Assess Meals -Intrc	11921000	11920000	69.97
853080	Assess Meals -Intrc	11921000	11920000	13.15
853085	Assess Travel-Intrc	11921000	11920000	553.45
853085	Assess Travel-Intrc	11921000	11920000	147.60
501100	Trvl Exp	11921000	11920000	15,073.94
501300	Meals & Ent	11921000	11920000	921.29
502130	Comp Exp-Software	11921000	11920000	163.95
502700	Office Related Exp	11921000	11920000	25,062.93
503200	Dues & Memberships	11921000	11920000	93,094.12
503200	Dues & Memberships	11921000	11920000	26,573.04
505000	Other Operating Exp	11921000	11920000	-
853040	Assess Other-Intrc	11921000	11920000	163.95
853040	Assess Other-Intrc	11921000	11920000	14,191.84
853040	Assess Other-Intrc	11921000	11920000	2,592.45
853040	Assess Other-Intrc	11921000	11920000	14,832.05
853050	As Fleet - Intrc	11921000	11920000	3.62
853050	As Fleet - Intrc	11921000	11920000	77.32
853080	Assess Meals -Intrc	11921000	11920000	2,797.98
853080	Assess Meals -Intrc	11921000	11920000	11.09
853080	Assess Meals -Intrc	11921000	11920000	1,722.07
853085	Assess Travel-Intrc	11921000	11920000	1,816.85
853085	Assess Travel-Intrc	11921000	11920000	7.26
853085	Assess Travel-Intrc	11921000	11920000	3,933.91
501300	Meals & Ent	11921000	11920000	79.82
502700	Office Related Exp	11921000	11920000	3,387.11
502700	Office Related Exp	11921000	11920000	19.41

853040	Assess Other-Intrc	11921000	11920000	(113.69)
853040	Assess Other-Intrc	11921000	11920000	1,860.48
853040	Assess Other-Intrc	11921000	11920000	(445.19)
853050	As Fleet - Intrc	11921000	11920000	5.26
853080	Assess Meals -Intrc	11921000	11920000	250.29
853080	Assess Meals -Intrc	11921000	11920000	11.36
853080	Assess Meals -Intrc	11921000	11920000	16.25
853085	Assess Travel-Intrc	11921000	11920000	41.61
853085	Assess Travel-Intrc	11921000	11920000	783.90
853085	Assess Travel-Intrc	11921000	11920000	127.50
501100	Trvl Exp	11921000	11920000	4,218.29
501110	Trvl Exp-Accomm	11921000	11920000	86.00
501130	Trvl Exp-Rental	11921000	11920000	1.40
501140	Trvl Exp-Mileage	11921000	11920000	257.25
501300	Meals & Ent	11921000	11920000	387.44
502700	Office Related Exp	11921000	11920000	9,625.07
502700	Office Related Exp	11921000	11920000	107.82
503110	Training	11921000	11920000	31,613.84
503200	Dues & Memberships	11921000	11920000	75.00
853085	Assess Travel-Intrc	11921000	11920000	344.65
853040	Assess Other-Intrc	11921000	11920000	(17,075.51)
853080	Assess Meals -Intrc	11921000	11920000	2,054.66
853080	Assess Meals -Intrc	11921000	11920000	457.98
853085	Assess Travel-Intrc	11921000	11920000	536.19
853085	Assess Travel-Intrc	11921000	11920000	431.62
502700	Office Related Exp	11921000	11920000	7,294.29
853040	Assess Other-Intrc	11921000	11920000	8,378.50
853040	Assess Other-Intrc	11921000	11920000	204.34
853050	As Fleet - Intrc	11921000	11920000	3.25
853080	Assess Meals -Intrc	11921000	11920000	159.33
853080	Assess Meals -Intrc	11921000	11920000	3.82
853085	Assess Travel-Intrc	11921000	11920000	577.86
853085	Assess Travel-Intrc	11921000	11920000	168.99
501130	Trvl Exp-Rental	11921000	11880000	4,672.77
502700	Office Related Exp	11921000	11880000	182.58
503110	Training	11921000	11880000	40,912.97
853040	Assess Other-Intrc	11921000	11920000	2,927.23
853080	Assess Meals -Intrc	11921000	11920000	29.63
853085	Assess Travel-Intrc	11921000	11920000	102.38
853040	Assess Other-Intrc	11921000	11920000	896.55
853040	Assess Other-Intrc	11921000	11920000	602.74
853050	As Fleet - Intrc	11921000	11920000	19.07
853080	Assess Meals -Intrc	11921000	11920000	218.80
853085	Assess Travel-Intrc	11921000	11920000	236.68

500920	Util Exp-Heat & Elec	11921000	11920000	133.10
501100	Trvl Exp	11921000	11920000	819.31
501400	Comm Exp-Telephone	11921000	11920000	1,224,685.85
501400	Comm Exp-Telephone	11921000	11920000	(955.56)
501400	Comm Exp-Telephone	11921000	11920000	221,334.54
501400	Comm Exp-Telephone	11921000	11920000	(46,997.62)
501420	Comm Exp-Internet	11921000	11920000	333.13
502130	Comp Exp-Software	11921000	11920000	(26,109.69)
502700	Office Related Exp	11921000	11920000	388,464.87
502700	Office Related Exp	11921000	11920000	496.75
502700	Office Related Exp	11921000	11920000	71,617.33
503110	Training	11921000	11920000	251.83
853020	As Mat -Intrc	11921000	11920000	7,990.85
853020	As Mat -Intrc	11921000	11920000	91.45
853040	Assess Other-Intrc	11921000	11920000	28,617.65
853040	Assess Other-Intrc	11921000	11920000	151,559.99
853040	Assess Other-Intrc	11921000	11920000	2,208.26
853050	As Fleet - Intrc	11921000	11920000	9.53
853080	Assess Meals -Intrc	11921000	11920000	40.70
853080	Assess Meals -Intrc	11921000	11920000	186.84
853080	Assess Meals -Intrc	11921000	11920000	170.72
853085	Assess Travel-Intrc	11921000	11920000	65.97
853085	Assess Travel-Intrc	11921000	11920000	1,271.80
853085	Assess Travel-Intrc	11921000	11920000	702.99
853040	Assess Other-Intrc	11921000	11920000	642.50
853040	Assess Other-Intrc	11921000	11920000	429.00
853050	As Fleet - Intrc	11921000	11920000	4.39
853080	Assess Meals -Intrc	11921000	11920000	78.47
853085	Assess Travel-Intrc	11921000	11920000	5.58
853085	Assess Travel-Intrc	11921000	11920000	414.28
853040	Assess Other-Intrc	11921000	11920000	2,279.56
853040	Assess Other-Intrc	11921000	11920000	(7,006.20)
853050	As Fleet - Intrc	11921000	11920000	(8.16)
853080	Assess Meals -Intrc	11921000	11920000	(13.21)
853080	Assess Meals -Intrc	11921000	11920000	(18.71)
853085	Assess Travel-Intrc	11921000	11920000	(0.49)
853085	Assess Travel-Intrc	11921000	11920000	(112.48)
853040	Assess Other-Intrc	11921000	11920000	(8,442.28)
853040	Assess Other-Intrc	11921000	11920000	(6,856.54)
853050	As Fleet - Intrc	11921000	11920000	(30.15)
853050	As Fleet - Intrc	11921000	11920000	(16.97)
853080	Assess Meals -Intrc	11921000	11920000	(337.36)
853080	Assess Meals -Intrc	11921000	11920000	(116.08)
853085	Assess Travel-Intrc	11921000	11920000	(1,153.32)

853085	Assess Travel-Intrc	11921000	11920000	(984.29)
853040	Assess Other-Intrc	11921000	11920000	(6,027.58)
853040	Assess Other-Intrc	11921000	11920000	(12,507.84)
853050	As Fleet - Intrc	11921000	11920000	(25.85)
853050	As Fleet - Intrc	11921000	11920000	(18.06)
853080	Assess Meals -Intrc	11921000	11920000	(65.86)
853080	Assess Meals -Intrc	11921000	11920000	(459.31)
853085	Assess Travel-Intrc	11921000	11920000	(576.91)
853085	Assess Travel-Intrc	11921000	11920000	(2,606.79)
853040	Assess Other-Intrc	11921000	11920000	(27,891.41)
853040	Assess Other-Intrc	11921000	11920000	(16,407.98)
853050	As Fleet - Intrc	11921000	11920000	(16.92)
853050	As Fleet - Intrc	11921000	11920000	(335.05)
853080	Assess Meals -Intrc	11921000	11920000	(780.47)
853080	Assess Meals -Intrc	11921000	11920000	(3,082.28)
853085	Assess Travel-Intrc	11921000	11920000	(1,525.43)
853085	Assess Travel-Intrc	11921000	11920000	(6,886.15)
501100	Trvl Exp	11921000	11920000	-
501400	Comm Exp-Telephone	11921000	11920000	101.52
502700	Office Related Exp	11921000	11920000	86,883.86
502700	Office Related Exp	11921000	11920000	1,213.92
502700	Office Related Exp	11921000	11920000	5,548.96
502700	Office Related Exp	11921000	11920000	5,629.67
503110	Training	11921000	11920000	40.60
853040	Assess Other-Intrc	11921000	11920000	42,358.31
853040	Assess Other-Intrc	11921000	11920000	488.04
853040	Assess Other-Intrc	11921000	11920000	28,173.01
853040	Assess Other-Intrc	11921000	11920000	1,609.78
853050	As Fleet - Intrc	11921000	11920000	9.21
853080	Assess Meals -Intrc	11921000	11920000	1,249.68
853080	Assess Meals -Intrc	11921000	11920000	428.63
853080	Assess Meals -Intrc	11921000	11920000	30.81
853085	Assess Travel-Intrc	11921000	11920000	760.32
853085	Assess Travel-Intrc	11921000	11920000	504.46
853085	Assess Travel-Intrc	11921000	11920000	334.68
853040	Assess Other-Intrc	11921000	11920000	(1,520.73)
853080	Assess Meals -Intrc	11921000	11920000	(0.28)
853040	Assess Other-Intrc	11921000	11920000	2,706.83
853050	As Fleet - Intrc	11921000	11920000	1.50
853080	Assess Meals -Intrc	11921000	11920000	(754.91)
853085	Assess Travel-Intrc	11921000	11920000	252.88
853040	Assess Other-Intrc	11921000	11920000	19,831.19
853040	Assess Other-Intrc	11921000	11920000	75.20
853080	Assess Meals -Intrc	11921000	11920000	61.84

853085	Assess Travel-Intrc	11921000	11920000	58.71
853040	Assess Other-Intrc	11921000	11920000	336.04
853040	Assess Other-Intrc	11921000	11920000	117.12
853080	Assess Meals -Intrc	11921000	11920000	22.10
853085	Assess Travel-Intrc	11921000	11920000	307.11
853085	Assess Travel-Intrc	11921000	11920000	16.56
853040	Assess Other-Intrc	11921000	11920000	13.97
853040	Assess Other-Intrc	11921000	11920000	182.01
853050	As Fleet - Intrc	11921000	11920000	17.56
853080	Assess Meals -Intrc	11921000	11920000	5.71
853085	Assess Travel-Intrc	11921000	11920000	87.43
853040	Assess Other-Intrc	11921000	11920000	73.00
853040	Assess Other-Intrc	11921000	11920000	21.84
853080	Assess Meals -Intrc	11921000	11920000	59.23
853080	Assess Meals -Intrc	11921000	11920000	36.54
853085	Assess Travel-Intrc	11921000	11920000	96.97
853085	Assess Travel-Intrc	11921000	11920000	105.71
853040	Assess Other-Intrc	11921000	11920000	19.02
853040	Assess Other-Intrc	11921000	11920000	28.90
853050	As Fleet - Intrc	11921000	11920000	4.20
853050	As Fleet - Intrc	11921000	11920000	3.20
853080	Assess Meals -Intrc	11921000	11920000	41.25
853080	Assess Meals -Intrc	11921000	11920000	217.33
853085	Assess Travel-Intrc	11921000	11920000	189.48
853085	Assess Travel-Intrc	11921000	11920000	430.78
853040	Assess Other-Intrc	11921000	11920000	12.64
853040	Assess Other-Intrc	11921000	11920000	285.72
853050	As Fleet - Intrc	11921000	11920000	4.05
853080	Assess Meals -Intrc	11921000	11920000	23.08
853085	Assess Travel-Intrc	11921000	11920000	213.60
501100	Trvl Exp	11921000	11920000	289.72
501300	Meals & Ent	11921000	11920000	38.40
501400	Comm Exp-Telephone	11921000	11920000	154.19
502700	Office Related Exp	11921000	11920000	37,104.47
502700	Office Related Exp	11921000	11920000	34.19
503110	Training	11921000	11920000	2,075.65
503200	Dues & Memberships	11921000	11920000	7,294.89
853020	As Mat -Intrc	11921000	11920000	(34.76)
853040	Assess Other-Intrc	11921000	11920000	(952.87)
853040	Assess Other-Intrc	11921000	11920000	737.71
853040	Assess Other-Intrc	11921000	11920000	(943.25)
853050	As Fleet - Intrc	11921000	11920000	18.53
853050	As Fleet - Intrc	11921000	11920000	52.27
853050	As Fleet - Intrc	11921000	11920000	5.60

853080	Assess Meals -Intrc	11921000	11920000	112.40
853080	Assess Meals -Intrc	11921000	11920000	237.95
853080	Assess Meals -Intrc	11921000	11920000	115.57
853085	Assess Travel-Intrc	11921000	11920000	500.06
853085	Assess Travel-Intrc	11921000	11920000	1,855.42
853085	Assess Travel-Intrc	11921000	11920000	591.02
501100	Trvl Exp	11921000	11920000	-
502700	Office Related Exp	11921000	11920000	429.00
853020	As Mat -Intrc	11921000	11920000	10.33
853040	Assess Other-Intrc	11921000	11920000	14,129.28
853040	Assess Other-Intrc	11921000	11920000	734.33
853050	As Fleet - Intrc	11921000	11920000	1.79
853050	As Fleet - Intrc	11921000	11920000	4.05
853080	Assess Meals -Intrc	11921000	11920000	147.65
853080	Assess Meals -Intrc	11921000	11920000	499.16
853085	Assess Travel-Intrc	11921000	11920000	227.85
853085	Assess Travel-Intrc	11921000	11920000	968.21
853040	Assess Other-Intrc	11921000	11920000	(74.29)
853040	Assess Other-Intrc	11921000	11920000	3,248.99
853050	As Fleet - Intrc	11921000	11920000	5.61
853080	Assess Meals -Intrc	11921000	11920000	79.94
853085	Assess Travel-Intrc	11921000	11920000	661.22
501100	Trvl Exp	11921000	11920000	245.92
501120	Trvl Exp-Airfare	11921000	11920000	1,317.09
501130	Trvl Exp-Rental	11921000	11920000	490.34
501300	Meals & Ent	11921000	11920000	53.52
501420	Comm Exp-Internet	11921000	11920000	476.33
502700	Office Related Exp	11921000	11920000	26,253.97
853040	Assess Other-Intrc	11921000	11920000	1,484.33
853080	Assess Meals -Intrc	11921000	11920000	53.52
853085	Assess Travel-Intrc	11921000	11920000	1,807.42
853040	Assess Other-Intrc	11921000	11920000	7,817.98
853040	Assess Other-Intrc	11921000	11920000	376.89
853050	As Fleet - Intrc	11921000	11920000	0.60
853050	As Fleet - Intrc	11921000	11920000	7.04
853080	Assess Meals -Intrc	11921000	11920000	149.40
853080	Assess Meals -Intrc	11921000	11920000	70.78
853085	Assess Travel-Intrc	11921000	11920000	285.76
853085	Assess Travel-Intrc	11921000	11920000	956.65
853040	Assess Other-Intrc	11921000	11920000	1,970.77
853040	Assess Other-Intrc	11921000	11920000	28.67
853080	Assess Meals -Intrc	11921000	11920000	20.06
853080	Assess Meals -Intrc	11921000	11920000	6.53
853085	Assess Travel-Intrc	11921000	11920000	122.18

853085	Assess Travel-Intrc	11921000	11920000	55.65
501100	Trvl Exp	11921000	11903000	1,284.05
501300	Meals & Ent	11921000	11903000	23.76
501300	Meals & Ent	11921000	11903000	114.36
502700	Office Related Exp	11921000	11903000	12,248.77
502700	Office Related Exp	11921000	11903000	64.76
502710	Postage	11921000	11903000	18.87
853020	As Mat -Intrc	11921000	11920000	16.52
853040	Assess Other-Intrc	11921000	11920000	5,560.47
853040	Assess Other-Intrc	11921000	11920000	5,612.35
853050	As Fleet - Intrc	11921000	11920000	16.69
853050	As Fleet - Intrc	11921000	11920000	18.11
853080	Assess Meals -Intrc	11921000	11920000	369.89
853080	Assess Meals -Intrc	11921000	11920000	217.21
853085	Assess Travel-Intrc	11921000	11920000	2,899.62
853085	Assess Travel-Intrc	11921000	11920000	863.72
501100	Trvl Exp	11921000	11912000	3,398.77
502700	Office Related Exp	11921000	11912000	852.39
502700	Office Related Exp	11921000	11912000	113.88
853040	Assess Other-Intrc	11921000	11920000	2,727.74
853040	Assess Other-Intrc	11921000	11920000	186.67
853050	As Fleet - Intrc	11921000	11920000	3.38
853050	As Fleet - Intrc	11921000	11920000	8.05
853080	Assess Meals -Intrc	11921000	11920000	253.71
853080	Assess Meals -Intrc	11921000	11920000	196.82
853085	Assess Travel-Intrc	11921000	11920000	982.06
853085	Assess Travel-Intrc	11921000	11920000	821.08
500495	M&C-Inventory Diff	11921000	11920000	54,534.85
500920	Util Exp-Heat & Elec	11921000	11920000	5,856.05
501100	Trvl Exp	11921000	11920000	14.27
502700	Office Related Exp	11921000	11920000	68,596.12
502700	Office Related Exp	11921000	11920000	112.89
502700	Office Related Exp	11921000	11920000	95.46
853020	As Mat -Intrc	11921000	11920000	(0.53)
853040	Assess Other-Intrc	11921000	11920000	(5,697.12)
853040	Assess Other-Intrc	11921000	11920000	3,422.39
853040	Assess Other-Intrc	11921000	11920000	271.69
853050	As Fleet - Intrc	11921000	11920000	5.77
853050	As Fleet - Intrc	11921000	11920000	6.06
853080	Assess Meals -Intrc	11921000	11920000	427.09
853080	Assess Meals -Intrc	11921000	11920000	262.94
853080	Assess Meals -Intrc	11921000	11920000	132.11
853085	Assess Travel-Intrc	11921000	11920000	769.37
853085	Assess Travel-Intrc	11921000	11920000	574.43

853085	Assess Travel-Intrc	11921000	11920000	454.47
500405	M&C-NonStck Cntrl	11921000	11886000	73,400.00
500405	M&C-NonStck Cntrl	11921000	11886000	(73,400.00)
500440	M&C-Spare Parts	11921000	11886000	62.00
500920	Util Exp-Heat & Elec	11921000	11920000	(237.71)
500930	Util Exp-Cust Instal	11921000	11920000	(230.51)
501100	Trvl Exp	11921000	11920000	6,145.54
502700	Office Related Exp	11921000	11920000	25,366.30
502700	Office Related Exp	11921000	11920000	589.49
502700	Office Related Exp	11921000	11920000	413.49
503000	Rental Expense	11921000	11920000	26,690.00
503110	Training	11921000	11920000	5,459.53
503200	Dues & Memberships	11921000	11920000	4,556.02
853040	Assess Other-Intrc	11921000	11920000	2,839,496.74
853040	Assess Other-Intrc	11921000	11920000	26,613.41
853040	Assess Other-Intrc	11921000	11920000	632.97
853050	As Fleet - Intrc	11921000	11920000	20.53
853050	As Fleet - Intrc	11921000	11920000	5.53
853080	Assess Meals -Intrc	11921000	11920000	388.19
853080	Assess Meals -Intrc	11921000	11920000	181.63
853085	Assess Travel-Intrc	11921000	11920000	826.46
853085	Assess Travel-Intrc	11921000	11920000	917.84
501100	Trvl Exp	11921000	11870000	9,575.76
501140	Trvl Exp-Mileage	11921000	11870000	174.14
501300	Meals & Ent	11921000	11870000	2,525.37
501300	Meals & Ent	11921000	11870000	37.79
501400	Comm Exp-Telephone	11921000	11870000	27.57
502700	Office Related Exp	11921000	11870000	2,131.98
502700	Office Related Exp	11921000	11870000	106.68
503110	Training	11921000	11870000	7,587.84
503200	Dues & Memberships	11921000	11870000	400.00
501110	Trvl Exp-Accomm	11921000	11870000	203.56
501130	Trvl Exp-Rental	11921000	11870000	83.03
501140	Trvl Exp-Mileage	11921000	11870000	771.25
501300	Meals & Ent	11921000	11870000	170.82
502700	Office Related Exp	11921000	11870000	89.27
502700	Office Related Exp	11921000	11920000	2.07
502700	Office Related Exp	11921000	11920000	0.93
853040	Assess Other-Intrc	11921000	11920000	542.62
853050	As Fleet - Intrc	11921000	11920000	1.66
853080	Assess Meals -Intrc	11921000	11920000	436.51
853085	Assess Travel-Intrc	11921000	11920000	783.92
501100	Trvl Exp	11921000	11871000	106.12
501300	Meals & Ent	11921000	11871000	127.48

501400	Comm Exp-Telephone	11921000	11871000	4,799.98
502700	Office Related Exp	11921000	11871000	2,435.15
502700	Office Related Exp	11921000	11871000	245.10
501130	Trvl Exp-Rental	11921000	11921000	(595,998.86)
550570	Cap Depr-Fleet	11921000	11921000	(147,204.64)
804085	WBS ST Travel	11921000	11921000	89,758.84
501300	Meals & Ent	11921000	11880000	52.65
502700	Office Related Exp	11921000	11880000	732.55
501130	Trvl Exp-Rental	11921000	11920000	147,204.64
502700	Office Related Exp	11921000	11920000	403.52
551100	Unrealized Gns/Lss	11921000	11920000	5,172.81
551100	Unrealized Gns/Lss	11921000	11920000	(6,897.08)
560010	Bank Charges	11921000	11920000	1,358.07
505000	Other Operating Exp	11921000	11920000	67,071.78
505000	Other Operating Exp	11921000	11920000	(67,071.78)
853040	Assess Other-Intrc	11921000	11920000	95,164.94
853040	Assess Other-Intrc	11921000	11920000	9,974.34
853040	Assess Other-Intrc	11921000	11920000	7,906.05
853040	Assess Other-Intrc	11921000	11920000	275,564.36
853040	Assess Other-Intrc	11921000	11920000	16,323.31
853080	Assess Meals -Intrc	11921000	11920000	55.08
853085	Assess Travel-Intrc	11921000	11920000	3,518.19
853085	Assess Travel-Intrc	11921000	11920000	78.74
500000	Salaries and Wages	11921000	11921000	64.06
500300	Outside Svs	11921000	11921000	1,119.06
500405	M&C-NonStck Cntrl	11921000	11735000	1,593.27
500405	M&C-NonStck Cntrl	11921000	11735000	4,758.45
500405	M&C-NonStck Cntrl	11921000	11886000	5.81
500405	M&C-NonStck Cntrl	11921000	11893000	211.06
500405	M&C-NonStck Cntrl	11921000	11921000	229.14
500405	M&C-NonStck Cntrl	11921000	11921000	9,470.80
500420	M&C-Safety Supplies	11921000	11880000	316.50
500920	Util Exp-Heat & Elec	11921000	11921000	6,372.99
501500	Advertising Expenses	11921000	11921000	1,463.86
501500	Advertising Expenses	11921000	11921000	220.76
501500	Advertising Expenses	11921000	11921000	(220.76)
502700	Office Related Exp	11921000	11735000	8.07
502700	Office Related Exp	11921000	11886000	275.10
502700	Office Related Exp	11921000	11921000	578.86
503200	Dues & Memberships	11921000	11921000	325.00
505000	Other Operating Exp	11921000	11921000	922.35
505000	Other Operating Exp	11921000	11921000	13,631.73
505000	Other Operating Exp	11921000	11921000	(760.73)
800000	Lbr Alloc	11921000	11921000	9,653.94

804000	WBS ST Lbr	11921000	11921000	(10,483.28)
804020	WBS ST Material	11921000	11921000	(9,699.94)
804030	WBS ST Services	11921000	11921000	(1,119.06)
804040	WBS ST Other	11921000	11921000	(22,534.06)
854000	WBS ST Lbr-Intrc	11921000	11921000	765.28
503110	Training	11921000	11920000	3,000.00
500405	M&C-NonStck Cntrl	11921000	11735000	3,436.69
500920	Util Exp-Heat & Elec	11921000	11920000	6,316.83
502700	Office Related Exp	11921000	11920000	49,693.92
502700	Office Related Exp	11921000	11920000	141.13
500430	M&C-Main Parts	11921000	11920000	38.88
560010	Bank Charges	11921000	11920000	502.74
				6,280,347.64

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
503300	Misc Other Deduction	11922000	11922000	105.97
800000	Lbr Alloc	11922000	11922000	226.99
804000	WBS ST Lbr	11922000	11922000	(226.99)
804040	WBS ST Other	11922000	11922000	(105.97)
803000	Assess Lbr	11922000	11920000	-
500000	Salaries and Wages	11922000	11920000	(28,891.85)
505100	Cost Alloc to Cap	11922000	11920000	(190,991.31)
803000	Assess Lbr	11922000	11920000	(4,167.04)
803040	Assess Other	11922000	11920000	(236.01)
803050	Assess Fleet - Asses	11922000	11920000	(18.57)
803080	Assess Meals	11922000	11920000	(35.86)
803085	Assess Travel	11922000	11920000	(558.17)
803000	Assess Lbr	11922000	11920000	(3,325.31)
803040	Assess Other	11922000	11920000	31,316.48
803050	Assess Fleet - Asses	11922000	11920000	(1.86)
803080	Assess Meals	11922000	11920000	(26.59)
803085	Assess Travel	11922000	11920000	(224.34)
500000	Salaries and Wages	11922000	11920000	(67,049.36)
505000	Other Operating Exp	11922000	11920000	-
505100	Cost Alloc to Cap	11922000	11920000	(508,704.84)
803000	Assess Lbr	11922000	11920000	(3,923.77)
803000	Assess Lbr	11922000	11920000	7,288.89
803020	Assess Material	11922000	11920000	192.49
803040	Assess Other	11922000	11920000	1,316.44
803080	Assess Meals	11922000	11920000	3,718.90
803085	Assess Travel	11922000	11920000	9,512.07
803000	Assess Lbr	11922000	11920000	(14,938.80)
803040	Assess Other	11922000	11920000	(10,117.23)
803050	Assess Fleet - Asses	11922000	11920000	(25.90)

803080	Assess Meals	11922000	11920000	(1,449.97)
803085	Assess Travel	11922000	11920000	(1,842.57)
500000	Salaries and Wages	11922000	11920000	(20,885.57)
505100	Cost Alloc to Cap	11922000	11920000	(74,912.00)
803000	Assess Lbr	11922000	11920000	(1,027.35)
803000	Assess Lbr	11922000	11920000	(1,566.53)
803040	Assess Other	11922000	11920000	449.78
803080	Assess Meals	11922000	11920000	197.27
803085	Assess Travel	11922000	11920000	3,287.39
803000	Assess Lbr	11922000	11920000	(11,096.51)
803040	Assess Other	11922000	11920000	(416.51)
803050	Assess Fleet - Asses	11922000	11920000	(1.69)
803080	Assess Meals	11922000	11920000	(88.92)
803085	Assess Travel	11922000	11920000	(304.97)
505100	Cost Alloc to Cap	11922000	11920000	(51,474.41)
803000	Assess Lbr	11922000	11920000	(4,933.97)
803080	Assess Meals	11922000	11920000	91.44
803085	Assess Travel	11922000	11920000	334.69
803000	Assess Lbr	11922000	11920000	(13,525.90)
803040	Assess Other	11922000	11920000	5,464.17
803080	Assess Meals	11922000	11920000	(804.05)
803085	Assess Travel	11922000	11920000	(309.70)
803000	Assess Lbr	11922000	11920000	(8,991.66)
803040	Assess Other	11922000	11920000	(2,746.50)
803050	Assess Fleet - Asses	11922000	11920000	(1.04)
803080	Assess Meals	11922000	11920000	(52.20)
803085	Assess Travel	11922000	11920000	(238.99)
505100	Cost Alloc to Cap	11922000	11880000	(23,194.91)
803000	Assess Lbr	11922000	11920000	(2,632.63)
803020	Assess Material	11922000	11920000	(241.19)
803040	Assess Other	11922000	11920000	(75.70)
803080	Assess Meals	11922000	11920000	(26.50)
803085	Assess Travel	11922000	11920000	(21.19)
803000	Assess Lbr	11922000	11920000	346.28
803040	Assess Other	11922000	11920000	(936.70)
803080	Assess Meals	11922000	11920000	(9.48)
803085	Assess Travel	11922000	11920000	(32.76)
803000	Assess Lbr	11922000	11920000	(4,805.92)
803040	Assess Other	11922000	11920000	(479.77)
803050	Assess Fleet - Asses	11922000	11920000	(6.10)
803080	Assess Meals	11922000	11920000	(70.01)
803085	Assess Travel	11922000	11920000	(75.73)
500000	Salaries and Wages	11922000	11920000	(2,287.74)
505100	Cost Alloc to Cap	11922000	11920000	(3,130.18)

803000	Assess Lbr	11922000	11920000	(23,538.87)
803020	Assess Material	11922000	11920000	(2,586.34)
803040	Assess Other	11922000	11920000	(58,363.49)
803050	Assess Fleet - Asses	11922000	11920000	(3.05)
803080	Assess Meals	11922000	11920000	(127.45)
803085	Assess Travel	11922000	11920000	(653.05)
803000	Assess Lbr	11922000	11920000	(8,494.57)
803040	Assess Other	11922000	11920000	(342.88)
803050	Assess Fleet - Asses	11922000	11920000	(1.41)
803080	Assess Meals	11922000	11920000	(25.11)
803085	Assess Travel	11922000	11920000	(134.36)
803000	Assess Lbr	11922000	11920000	632.71
803040	Assess Other	11922000	11920000	1,512.53
803050	Assess Fleet - Asses	11922000	11920000	2.62
803080	Assess Meals	11922000	11920000	10.21
803085	Assess Travel	11922000	11920000	36.15
803000	Assess Lbr	11922000	11920000	(232.45)
803040	Assess Other	11922000	11920000	4,895.62
803050	Assess Fleet - Asses	11922000	11920000	15.07
803080	Assess Meals	11922000	11920000	145.10
803085	Assess Travel	11922000	11920000	684.03
803000	Assess Lbr	11922000	11920000	(796.79)
803040	Assess Other	11922000	11920000	5,931.34
803050	Assess Fleet - Asses	11922000	11920000	14.05
803080	Assess Meals	11922000	11920000	168.05
803085	Assess Travel	11922000	11920000	1,018.78
803000	Assess Lbr	11922000	11920000	(448.09)
803040	Assess Other	11922000	11920000	14,175.80
803050	Assess Fleet - Asses	11922000	11920000	112.62
803080	Assess Meals	11922000	11920000	1,236.08
803085	Assess Travel	11922000	11920000	2,691.70
500000	Salaries and Wages	11922000	11920000	(40,715.18)
505100	Cost Alloc to Cap	11922000	11920000	(1,298,139.58)
803000	Assess Lbr	11922000	11920000	(13,591.30)
803000	Assess Lbr	11922000	11920000	5,201.51
803020	Assess Material	11922000	11920000	104.99
803040	Assess Other	11922000	11920000	1,706.94
803080	Assess Meals	11922000	11920000	23.23
803000	Assess Lbr	11922000	11920000	20,093.15
803040	Assess Other	11922000	11920000	(23,241.32)
803050	Assess Fleet - Asses	11922000	11920000	(2.94)
803080	Assess Meals	11922000	11920000	(546.92)
803085	Assess Travel	11922000	11920000	(511.83)
803000	Assess Lbr	11922000	11920000	185.41

803040	Assess Other	11922000	11920000	486.63
803080	Assess Meals	11922000	11920000	0.09
803000	Assess Lbr	11922000	11920000	(12,260.36)
803040	Assess Other	11922000	11920000	(866.18)
803050	Assess Fleet - Asses	11922000	11920000	(0.48)
803080	Assess Meals	11922000	11920000	241.57
803085	Assess Travel	11922000	11920000	(80.92)
505100	Cost Alloc to Cap	11922000	11920000	(42,708.96)
803000	Assess Lbr	11922000	11920000	(11,037.65)
803040	Assess Other	11922000	11920000	(6,370.04)
803080	Assess Meals	11922000	11920000	(19.79)
803085	Assess Travel	11922000	11920000	(18.79)
803000	Assess Lbr	11922000	11920000	(4,025.53)
803040	Assess Other	11922000	11920000	(145.02)
803080	Assess Meals	11922000	11920000	(7.07)
803085	Assess Travel	11922000	11920000	(103.58)
803000	Assess Lbr	11922000	11920000	(2,300.05)
803040	Assess Other	11922000	11920000	(62.72)
803050	Assess Fleet - Asses	11922000	11920000	(5.62)
803080	Assess Meals	11922000	11920000	(1.83)
803085	Assess Travel	11922000	11920000	(27.98)
803000	Assess Lbr	11922000	11920000	(2,135.54)
803040	Assess Other	11922000	11920000	(30.35)
803080	Assess Meals	11922000	11920000	(30.64)
803085	Assess Travel	11922000	11920000	(64.86)
803000	Assess Lbr	11922000	11920000	(1,525.15)
803040	Assess Other	11922000	11920000	(15.34)
803050	Assess Fleet - Asses	11922000	11920000	(2.37)
803080	Assess Meals	11922000	11920000	(82.75)
803085	Assess Travel	11922000	11920000	(198.49)
803000	Assess Lbr	11922000	11920000	(3,068.70)
803040	Assess Other	11922000	11920000	(95.48)
803050	Assess Fleet - Asses	11922000	11920000	(1.29)
803080	Assess Meals	11922000	11920000	(7.39)
803085	Assess Travel	11922000	11920000	(68.35)
500000	Salaries and Wages	11922000	11920000	(41,741.26)
505100	Cost Alloc to Cap	11922000	11920000	(280,024.78)
803000	Assess Lbr	11922000	11920000	(12,612.80)
803000	Assess Lbr	11922000	11920000	(7,091.41)
803040	Assess Other	11922000	11920000	105.00
803080	Assess Meals	11922000	11920000	16.90
803085	Assess Travel	11922000	11920000	450.03
803000	Assess Lbr	11922000	11920000	(1,129.66)
803020	Assess Material	11922000	11920000	11.12

803040	Assess Other	11922000	11920000	370.70
803050	Assess Fleet - Asses	11922000	11920000	(24.45)
803080	Assess Meals	11922000	11920000	(149.09)
803085	Assess Travel	11922000	11920000	(942.88)
803000	Assess Lbr	11922000	11920000	(12,914.47)
803020	Assess Material	11922000	11920000	(3.31)
803040	Assess Other	11922000	11920000	(4,756.36)
803050	Assess Fleet - Asses	11922000	11920000	(1.87)
803080	Assess Meals	11922000	11920000	(206.98)
803085	Assess Travel	11922000	11920000	(382.75)
803000	Assess Lbr	11922000	11920000	(1,234.22)
803040	Assess Other	11922000	11920000	(1,015.90)
803050	Assess Fleet - Asses	11922000	11920000	(1.80)
803080	Assess Meals	11922000	11920000	(25.58)
803085	Assess Travel	11922000	11920000	(211.59)
500000	Salaries and Wages	11922000	11920000	(20,716.53)
505100	Cost Alloc to Cap	11922000	11920000	(269,074.97)
803000	Assess Lbr	11922000	11920000	743.04
803000	Assess Lbr	11922000	11920000	(3,761.43)
803040	Assess Other	11922000	11920000	1,463.00
803080	Assess Meals	11922000	11920000	56.48
803085	Assess Travel	11922000	11920000	3,694.43
803000	Assess Lbr	11922000	11920000	(2,777.25)
803040	Assess Other	11922000	11920000	(2,622.36)
803050	Assess Fleet - Asses	11922000	11920000	(2.45)
803080	Assess Meals	11922000	11920000	(70.46)
803085	Assess Travel	11922000	11920000	(397.57)
803000	Assess Lbr	11922000	11920000	(1,477.39)
803040	Assess Other	11922000	11920000	(639.82)
803080	Assess Meals	11922000	11920000	(8.51)
803085	Assess Travel	11922000	11920000	(56.90)
505100	Cost Alloc to Cap	11922000	11903000	(653,704.73)
803000	Assess Lbr	11922000	11920000	(11,911.03)
803020	Assess Material	11922000	11920000	(5.29)
803040	Assess Other	11922000	11920000	(3,575.30)
803050	Assess Fleet - Asses	11922000	11920000	(11.13)
803080	Assess Meals	11922000	11920000	(187.87)
803085	Assess Travel	11922000	11920000	(1,204.26)
500000	Salaries and Wages	11922000	11912000	(240,084.50)
505100	Cost Alloc to Cap	11922000	11912000	(337,232.58)
803000	Assess Lbr	11922000	11920000	1,982.51
803040	Assess Other	11922000	11920000	(6.40)
803000	Assess Lbr	11922000	11920000	(18,617.56)
803000	Assess Lbr	11922000	11920000	14,881.75

803040	Assess Other	11922000	11920000	163.17
803085	Assess Travel	11922000	11920000	129.16
505100	Cost Alloc to Cap	11922000	11920000	(26,478.74)
803000	Assess Lbr	11922000	11920000	(330.01)
803000	Assess Lbr	11922000	11920000	(3,028.50)
803040	Assess Other	11922000	11920000	(932.61)
803050	Assess Fleet - Asses	11922000	11920000	(3.66)
803080	Assess Meals	11922000	11920000	(144.17)
803085	Assess Travel	11922000	11920000	(577.01)
500000	Salaries and Wages	11922000	11920000	(43,378.96)
505100	Cost Alloc to Cap	11922000	11920000	(578,798.55)
803000	Assess Lbr	11922000	11920000	(10,176.69)
803000	Assess Lbr	11922000	11920000	(68,740.42)
803020	Assess Material	11922000	11920000	4,228.79
803040	Assess Other	11922000	11920000	1,909.84
803080	Assess Meals	11922000	11920000	235.20
803085	Assess Travel	11922000	11920000	622.79
803000	Assess Lbr	11922000	11920000	(5,656.01)
803020	Assess Material	11922000	11920000	0.17
803040	Assess Other	11922000	11920000	640.98
803050	Assess Fleet - Asses	11922000	11920000	(3.79)
803080	Assess Meals	11922000	11920000	(263.09)
803085	Assess Travel	11922000	11920000	(575.44)
803020	Assess Material	11922000	11920000	(629.80)
803040	Assess Other	11922000	11920000	(11,001.64)
500000	Salaries and Wages	11922000	11920000	(52,264.89)
505100	Cost Alloc to Cap	11922000	11920000	(5,294,692.21)
803000	Assess Lbr	11922000	11920000	-
803040	Assess Other	11922000	11920000	3,237,197.16
803080	Assess Meals	11922000	11920000	(18,281.00)
803000	Assess Lbr	11922000	11920000	(26,287.82)
803040	Assess Other	11922000	11920000	3,632.68
803085	Assess Travel	11922000	11920000	2.20
803000	Assess Lbr	11922000	11920000	5,158.77
803040	Assess Other	11922000	11920000	(8,718.84)
803050	Assess Fleet - Asses	11922000	11920000	(8.34)
803080	Assess Meals	11922000	11920000	(182.35)
803085	Assess Travel	11922000	11920000	(558.18)
500000	Salaries and Wages	11922000	11870000	(54,102.74)
505100	Cost Alloc to Cap	11922000	11870000	(755,707.89)
505100	Cost Alloc to Cap	11922000	11920000	(249,148.08)
803000	Assess Lbr	11922000	11920000	(33,576.85)
803040	Assess Other	11922000	11920000	(173.64)
803050	Assess Fleet - Asses	11922000	11920000	(0.53)

803080	Assess Meals	11922000	11920000	(139.67)
803085	Assess Travel	11922000	11920000	(250.85)
505100	Cost Alloc to Cap	11922000	11871000	(454,425.38)
803000	Assess Lbr	11922000	11920000	(36,960.07)
803040	Assess Other	11922000	11920000	(61.73)
803080	Assess Meals	11922000	11920000	(32.40)
803085	Assess Travel	11922000	11920000	(162.10)
803000	Assess Lbr	11922000	11920000	(18,411.36)
803040	Assess Other	11922000	11920000	2,320.98
803080	Assess Meals	11922000	11920000	53.50
803085	Assess Travel	11922000	11920000	1,296.79
803040	Assess Other	11922000	11920000	6,871.74
803000	Assess Lbr	11922000	11920000	(84,912.77)
803000	Assess Lbr	11922000	11920000	172,950.48
803040	Assess Other	11922000	11920000	42,339.87
803040	Assess Other	11922000	11920000	(124,355.10)
803050	Assess Fleet - Asses	11922000	11920000	35.76
803080	Assess Meals	11922000	11920000	48.47
803080	Assess Meals	11922000	11920000	(17.63)
803085	Assess Travel	11922000	11920000	6.85
803085	Assess Travel	11922000	11920000	(1,151.02)
500000	Salaries and Wages	11922000	11922000	4,485.92
800000	Lbr Alloc	11922000	11922000	474.68
804000	WBS ST Lbr	11922000	11922000	(4,960.60)
505100	Cost Alloc to Cap	11922000	11920000	(49,645.72)
				(8,946,903.70)

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500300	Outside Svs	11923000	11920000	42,738.85
500300	Outside Svs	11923000	11920000	1,550.00
500300	Outside Svs	11923000	11923000	38,879.70
500310	Outside Svs-Engineer	11923000	11923000	5,040.00
500400	Materials & Supplies	11923000	11923000	188.50
502540	Prof Svs-Other	11923000	11804000	1,477.95
502540	Prof Svs-Other	11923000	11903000	6,699.70
502540	Prof Svs-Other	11923000	11920000	76,336.75
502540	Prof Svs-Other	11923000	11923000	52,150.73
505000	Other Operating Exp	11923000	11923000	5,628.46
505000	Other Operating Exp	11923000	11923000	9,810.00
804020	WBS ST Material	11923000	11923000	(188.50)
804030	WBS ST Services	11923000	11923000	(43,919.70)
804040	WBS ST Other	11923000	11923000	(67,589.19)
502540	Prof Svs-Other	11923000	11920000	2,450.00
803030	Assess Services	11923000	11920000	(1,872.02)

853030	As Serv-Intrc	11923000	11920000	5.44
853030	As Serv-Intrc	11923000	11920000	5,844.63
505000	Other Operating Exp	11923000	11920000	-
803030	Assess Services	11923000	11920000	(7,941.83)
853030	As Serv-Intrc	11923000	11920000	19,590.47
853030	As Serv-Intrc	11923000	11920000	1,094.22
853030	As Serv-Intrc	11923000	11920000	3,971.10
853030	As Serv-Intrc	11923000	11920000	162.43
502400	Legal Expenses	11923000	11920000	84,836.49
502540	Prof Svs-Other	11923000	11920000	132,679.68
502540	Prof Svs-Other	11923000	11920000	210.00
505210	AllocReg NonLbr Leg	11923000	11920000	3.39
803030	Assess Services	11923000	11920000	(551.58)
853030	As Serv-Intrc	11923000	11920000	1,723.69
502540	Prof Svs-Other	11923000	11920000	69,933.54
502540	Prof Svs-Other	11923000	11920000	98.34
502540	Prof Svs-Other	11923000	11920000	(1,697.50)
505210	AllocReg NonLbr Leg	11923000	11920000	38,450.56
502540	Prof Svs-Other	11923000	11920000	(26,909.64)
803030	Assess Services	11923000	11920000	(583.33)
853030	As Serv-Intrc	11923000	11920000	1,198.86
853030	As Serv-Intrc	11923000	11920000	525.07
853030	As Serv-Intrc	11923000	11920000	98.96
803030	Assess Services	11923000	11920000	(978.53)
853030	As Serv-Intrc	11923000	11920000	3,057.90
502540	Prof Svs-Other	11923000	11880000	1,106.30
803030	Assess Services	11923000	11920000	(5,964.43)
803030	Assess Services	11923000	11920000	(356.21)
853030	As Serv-Intrc	11923000	11920000	1,113.15
803030	Assess Services	11923000	11920000	(554.88)
853030	As Serv-Intrc	11923000	11920000	1,734.01
500300	Outside Svs	11923000	11920000	4,098.94
500300	Outside Svs	11923000	11920000	(177,422.98)
502540	Prof Svs-Other	11923000	11920000	51,098.82
803030	Assess Services	11923000	11920000	(8,551.44)
853030	As Serv-Intrc	11923000	11920000	13,016.33
853030	As Serv-Intrc	11923000	11920000	3,307.62
853030	As Serv-Intrc	11923000	11920000	10,399.33
803030	Assess Services	11923000	11920000	6,452.42
803030	Assess Services	11923000	11920000	(1,130.94)
853030	As Serv-Intrc	11923000	11920000	954.13
853030	As Serv-Intrc	11923000	11920000	2,580.07
803030	Assess Services	11923000	11920000	3,487.28
853030	As Serv-Intrc	11923000	11920000	(54.06)

853030	As Serv-Intrc	11923000	11920000	(10,843.68)
803030	Assess Services	11923000	11920000	(30.81)
853030	As Serv-Intrc	11923000	11920000	96.28
803030	Assess Services	11923000	11920000	8,347.45
853030	As Serv-Intrc	11923000	11920000	677.58
853030	As Serv-Intrc	11923000	11920000	(26,763.37)
803030	Assess Services	11923000	11920000	10,640.89
853030	As Serv-Intrc	11923000	11920000	(33,252.79)
500300	Outside Svs	11923000	11920000	2,853.76
502540	Prof Svs-Other	11923000	11920000	118,811.15
502540	Prof Svs-Other	11923000	11920000	22,680.00
502540	Prof Svs-Other	11923000	11920000	79,709.38
505210	AllocReg NonLbr Leg	11923000	11920000	33.54
803030	Assess Services	11923000	11920000	6,546.42
500300	Outside Svs	11923000	11920000	1,630.72
803030	Assess Services	11923000	11920000	(5,558.04)
853030	As Serv-Intrc	11923000	11920000	16,373.19
853030	As Serv-Intrc	11923000	11920000	971.43
853030	As Serv-Intrc	11923000	11920000	24.25
803030	Assess Services	11923000	11920000	(9.99)
853030	As Serv-Intrc	11923000	11920000	31.22
803030	Assess Services	11923000	11920000	(2,218.28)
853030	As Serv-Intrc	11923000	11920000	6,932.12
803030	Assess Services	11923000	11920000	(774.01)
853030	As Serv-Intrc	11923000	11920000	2,418.77
803030	Assess Services	11923000	11920000	(19.85)
853030	As Serv-Intrc	11923000	11920000	62.06
803030	Assess Services	11923000	11920000	(994.81)
853030	As Serv-Intrc	11923000	11920000	2,873.38
853030	As Serv-Intrc	11923000	11920000	235.40
803030	Assess Services	11923000	11920000	(184.92)
853030	As Serv-Intrc	11923000	11920000	577.89
803030	Assess Services	11923000	11920000	(1,274.42)
853030	As Serv-Intrc	11923000	11920000	3,805.47
853030	As Serv-Intrc	11923000	11920000	177.10
803030	Assess Services	11923000	11920000	(3.09)
853030	As Serv-Intrc	11923000	11920000	9.65
500300	Outside Svs	11923000	11920000	2,500.00
502540	Prof Svs-Other	11923000	11920000	47,079.68
505210	AllocReg NonLbr Leg	11923000	11920000	1,685.95
803030	Assess Services	11923000	11920000	(11.05)
853030	As Serv-Intrc	11923000	11920000	20.93
853030	As Serv-Intrc	11923000	11920000	13.59
502540	Prof Svs-Other	11923000	11920000	16,886.40

803030	Assess Services	11923000	11920000	(24.98)
853030	As Serv-Intrc	11923000	11920000	78.03
505200	AllocCorp NonLbr Leg	11923000	11920000	4,508.19
803030	Assess Services	11923000	11920000	(94.20)
853030	As Serv-Intrc	11923000	11920000	294.37
500300	Outside Svs	11923000	11920000	35,000.00
502540	Prof Svs-Other	11923000	11920000	-
803030	Assess Services	11923000	11920000	(3,057.62)
853030	As Serv-Intrc	11923000	11920000	4,584.35
853030	As Serv-Intrc	11923000	11920000	4,970.71
803030	Assess Services	11923000	11920000	(36.49)
853030	As Serv-Intrc	11923000	11920000	114.03
505210	AllocReg NonLbr Leg	11923000	11903000	14,535.38
500300	Outside Svs	11923000	11920000	(128,099.55)
803030	Assess Services	11923000	11920000	(900.30)
853030	As Serv-Intrc	11923000	11920000	2,813.45
502540	Prof Svs-Other	11923000	11912000	1,670.00
803030	Assess Services	11923000	11920000	(3,213.23)
853030	As Serv-Intrc	11923000	11920000	10,041.32
500300	Outside Svs	11923000	11920000	4,688.32
803030	Assess Services	11923000	11920000	(244.00)
853030	As Serv-Intrc	11923000	11920000	762.51
803030	Assess Services	11923000	11920000	(2,100.24)
500300	Outside Svs	11923000	11920000	104.62
500300	Outside Svs	11923000	11920000	(3,000.00)
500340	AllocCorp OutSvs Leg	11923000	11920000	595,555.11
500340	AllocCorp OutSvs Leg	11923000	11920000	879,939.49
502540	Prof Svs-Other	11923000	11920000	7,656.10
505200	AllocCorp NonLbr Leg	11923000	11920000	1,749,073.24
505210	AllocReg NonLbr Leg	11923000	11920000	1,339,745.57
500300	Outside Svs	11923000	11920000	1.43
803030	Assess Services	11923000	11920000	(3,956.57)
853030	As Serv-Intrc	11923000	11920000	12,310.77
853030	As Serv-Intrc	11923000	11920000	53.51
502540	Prof Svs-Other	11923000	11870000	195,203.06
502540	Prof Svs-Other	11923000	11920000	156,395.84
803030	Assess Services	11923000	11920000	(8.96)
853030	As Serv-Intrc	11923000	11920000	27.98
803030	Assess Services	11923000	11920000	36.79
500300	Outside Svs	11923000	11920000	92,408.28
803030	Assess Services	11923000	11920000	23,348.24
803030	Assess Services	11923000	11920000	(674.37)
853030	As Serv-Intrc	11923000	11920000	2,107.40
853030	As Serv-Intrc	11923000	11920000	115,805.97

500300	Outside Svs	11923000	11923000	77.15
502540	Prof Svs-Other	11923000	11880000	77.15
804030	WBS ST Services	11923000	11923000	(77.15)
500300	Outside Svs	11923000	11107000	12,900.00
500300	Outside Svs	11923000	11886000	2,777.50
				5,756,461.79

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
853114	As Prop Ins-Intrc	11924000	11920000	20.54
501010	Property Insurance	11924000	11920000	68,092.50
501010	Property Insurance	11924000	11920000	24,390.09
853114	As Prop Ins-Intrc	11924000	11920000	153.06
501010	Property Insurance	11924000	11920000	501.36
853114	As Prop Ins-Intrc	11924000	11920000	501.36
501010	Property Insurance	11924000	11920000	27,076.14
501010	Property Insurance	11924000	11920000	9,378.58
				130,113.63

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500300	Outside Svs	11925000	11925000	514.00
804030	WBS ST Services	11925000	11925000	(514.00)
505000	Other Operating Exp	11925000	11920000	-
501050	Inj & Damages Insrce	11925000	11920000	793,050.09
501050	Inj & Damages Insrce	11925000	11920000	268,251.30
501050	Inj & Damages Insrce	11925000	11920000	15,088.49
501050	Inj & Damages Insrce	11925000	11920000	446.13
501050	Inj & Damages Insrce	11925000	11920000	264,195.74
501050	Inj & Damages Insrce	11925000	11920000	82,306.01
				1,423,337.76

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500150	Medicare/Healthcare	11926000	11926000	(131,470.57)
500160	RRSP/DPSP/401K	11926000	11926000	620,464.90
500170	Group/Emp Ben	11926000	11926000	(40,170.08)
578010	OPEB Non-Srv Cst	11926000	11926000	43,266.48
578020	Pension Nn-Srv Costs	11926000	11926000	(408,667.08)
702110	BS Ops OH Benefit	11926000	11926000	(309,489.63)
702117	BS OH PenOPEB Nonser	11926000	11926000	365,400.60
853110	As OH BenIntrc	11926000	11920000	8,829.78
853110	As OH BenIntrc	11926000	11920000	6,754.09
853110	As OH BenIntrc	11926000	11920000	1,526.28
500270	Car Allowance	11926000	11920000	581.53
853110	As OH BenIntrc	11926000	11920000	290.77
853110	As OH BenIntrc	11926000	11920000	107,323.00

853110	As OH BenIntrc	11926000	11920000	(111.12)
853110	As OH BenIntrc	11926000	11920000	118,902.30
853110	As OH BenIntrc	11926000	11920000	1,047.08
853110	As OH BenIntrc	11926000	11920000	16,742.97
853110	As OH BenIntrc	11926000	11920000	8,366.76
853110	As OH BenIntrc	11926000	11920000	27,109.92
853113	As Pnsn/OPEB-Intrc	11926000	11920000	36.49
500115	Ben Offst	11926000	11920000	(532,561.02)
500140	Opt Out Cr	11926000	11920000	16,247.42
500150	Medicare/Healthcare	11926000	11920000	3,286,821.92
500160	RRSP/DPSP/401K	11926000	11920000	674,785.74
500170	Group/Emp Ben	11926000	11920000	(657,991.94)
500230	StkPurPlns Emp Cntr	11926000	11920000	47,655.60
853110	As OH BenIntrc	11926000	11920000	(331.00)
853110	As OH BenIntrc	11926000	11920000	3,206.77
853110	As OH BenIntrc	11926000	11920000	4,376.47
853110	As OH BenIntrc	11926000	11920000	485.16
853110	As OH BenIntrc	11926000	11920000	12,947.64
853110	As OH BenIntrc	11926000	11920000	1,321.76
853110	As OH BenIntrc	11926000	11920000	718.54
853110	As OH BenIntrc	11926000	11920000	3,093.06
853110	As OH BenIntrc	11926000	11920000	355.38
853110	As OH BenIntrc	11926000	11920000	151.62
853110	As OH BenIntrc	11926000	11920000	17,851.95
853110	As OH BenIntrc	11926000	11920000	29,858.05
853110	As OH BenIntrc	11926000	11920000	3,800.85
853110	As OH BenIntrc	11926000	11920000	24,711.83
853110	As OH BenIntrc	11926000	11920000	1,635.60
853110	As OH BenIntrc	11926000	11920000	1,723.26
853110	As OH BenIntrc	11926000	11920000	885.34
853110	As OH BenIntrc	11926000	11920000	1,153.21
853110	As OH BenIntrc	11926000	11920000	3,231.32
853110	As OH BenIntrc	11926000	11920000	557.08
853110	As OH BenIntrc	11926000	11920000	5,956.18
853110	As OH BenIntrc	11926000	11920000	2,807.87
500150	Medicare/Healthcare	11926000	11920000	34,053.00
500150	Medicare/Healthcare	11926000	11920000	3,783.67
500160	RRSP/DPSP/401K	11926000	11920000	1,212,578.28
500160	RRSP/DPSP/401K	11926000	11920000	134,730.92
853110	As OH BenIntrc	11926000	11920000	16,719.58
853110	As OH BenIntrc	11926000	11920000	44,456.63
853110	As OH BenIntrc	11926000	11920000	10,064.66
853110	As OH BenIntrc	11926000	11920000	2,217.72
853110	As OH BenIntrc	11926000	11920000	10,309.99

853110	As OH BenIntrc	11926000	11920000	6,163.45
853110	As OH BenIntrc	11926000	11920000	(86.74)
853110	As OH BenIntrc	11926000	11920000	2,893.67
853110	As OH BenIntrc	11926000	11920000	149.30
853110	As OH BenIntrc	11926000	11920000	2,694.34
853110	As OH BenIntrc	11926000	11920000	2,236.47
853110	As OH BenIntrc	11926000	11920000	3,409.30
853110	As OH BenIntrc	11926000	11920000	1,988.39
853110	As OH BenIntrc	11926000	11920000	2,220.20
853110	As OH BenIntrc	11926000	11920000	2,721.85
853110	As OH BenIntrc	11926000	11920000	2,160.96
853110	As OH BenIntrc	11926000	11920000	11,199.31
853110	As OH BenIntrc	11926000	11920000	(742.37)
853110	As OH BenIntrc	11926000	11920000	4,609.08
853110	As OH BenIntrc	11926000	11920000	5,448.53
853110	As OH BenIntrc	11926000	11920000	7,477.80
853110	As OH BenIntrc	11926000	11920000	8,226.76
853110	As OH BenIntrc	11926000	11920000	4,646.60
853110	As OH BenIntrc	11926000	11920000	6,480.56
853110	As OH BenIntrc	11926000	11920000	1,540.83
853110	As OH BenIntrc	11926000	11920000	904.59
853110	As OH BenIntrc	11926000	11920000	(123.63)
853110	As OH BenIntrc	11926000	11920000	844.27
853110	As OH BenIntrc	11926000	11920000	145.73
853110	As OH BenIntrc	11926000	11920000	9,759.86
853110	As OH BenIntrc	11926000	11920000	3,725.85
853110	As OH BenIntrc	11926000	11920000	794.61
853110	As OH BenIntrc	11926000	11920000	20,118.15
853110	As OH BenIntrc	11926000	11920000	7,988.82
853113	As Pnsn/OPEB-Intrc	11926000	11920000	990.07
853110	As OH BenIntrc	11926000	11920000	505.97
853110	As OH BenIntrc	11926000	11920000	5,848.23
853110	As OH BenIntrc	11926000	11920000	(2,774.31)
853110	As OH BenIntrc	11926000	11920000	1,372.51
853110	As OH BenIntrc	11926000	11920000	11,010.15
853110	As OH BenIntrc	11926000	11920000	3,110.52
578010	OPEB Non-Srv Cst	11926000	11920000	129,799.50
578010	OPEB Non-Srv Cst	11926000	11920000	-
578020	Pension Nn-Srv Costs	11926000	11920000	(198,160.28)
578020	Pension Nn-Srv Costs	11926000	11920000	342,613.32
853110	As OH BenIntrc	11926000	11920000	(2,021.24)
853110	As OH BenIntrc	11926000	11920000	13,227.70
853110	As OH BenIntrc	11926000	11920000	2,230.17
853110	As OH BenIntrc	11926000	11920000	6,494.23

853110	As OH BenIntrc	11926000	11920000	2.38
853110	As OH BenIntrc	11926000	11920000	229.69
853110	As OH BenIntrc	11926000	11920000	16,242.73
853110	As OH BenIntrc	11926000	11920000	(183.07)
500115	Ben Offst	11926000	11920000	94,217.32
853110	As OH BenIntrc	11926000	11920000	(37,960.88)
853110	As OH BenIntrc	11926000	11920000	(71,071.11)
853110	As OH BenIntrc	11926000	11920000	(81,933.76)
853110	As OH BenIntrc	11926000	11920000	23,514.18
853113	As Pnsn/OPEB-Intrc	11926000	11920000	408.48
				5,238,413.62

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
505060	Reg Commisions Exp	11928000	11920000	4,200.00
505060	Reg Commisions Exp	11928000	11920000	552,406.02
505060	Reg Commisions Exp	11928000	11920000	533,598.00
505060	Reg Commisions Exp	11928000	11920000	368,270.67
505060	Reg Commisions Exp	11928000	11920000	(368,270.67)
				1,090,204.02

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11930200	11930200	7,832.27
500010	Overtime	11930200	11930200	23,194.66
500100	Vacation & Other TO	11930200	11930200	11,486.61
500300	Outside Svs	11930200	11930200	685.49
500405	M&C-NonStck Cntrl	11930200	11930200	79.99
500500	Equip & Machin Rents	11930200	11930200	3.98
502300	Facility Costs	11930200	11930200	250.00
505000	Other Operating Exp	11930200	11920000	2,573.48
505000	Other Operating Exp	11930200	11920000	110,210.00
505000	Other Operating Exp	11930200	11930200	3,651.30
800000	Lbr Alloc	11930200	11930200	2,925.12
804000	WBS ST Lbr	11930200	11930200	(33,952.05)
804020	WBS ST Material	11930200	11930200	(79.99)
804030	WBS ST Services	11930200	11930200	(685.49)
804040	WBS ST Other	11930200	11930200	(3,905.28)
804110	WBS ST OH Benefit	11930200	11930200	(11,486.61)
505000	Other Operating Exp	11930200	11920000	(4,618.76)
505000	Other Operating Exp	11930200	11920000	(5,654.98)
505000	Other Operating Exp	11930200	11920000	1,899.03
505000	Other Operating Exp	11930200	11920000	(24,979.80)
505000	Other Operating Exp	11930200	11920000	4,338.05
505000	Other Operating Exp	11930200	11920000	(13,062.55)
505000	Other Operating Exp	11930200	11920000	(6,524.25)

505000	Other Operating Exp	11930200	11903000	191.30
505000	Other Operating Exp	11930200	11920000	(5,631.11)
505000	Other Operating Exp	11930200	11920000	21,070.77
505000	Other Operating Exp	11930200	11920000	(134,536.04)
505000	Other Operating Exp	11930200	11920000	2,612.48
505000	Other Operating Exp	11930200	11920000	2,400.00
505000	Other Operating Exp	11930200	11920000	(3,094,621.95)
505000	Other Operating Exp	11930200	11920000	(47,257.70)
505000	Other Operating Exp	11930200	11920000	(29,905.71)
				(3,221,497.74)

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
503000	Rental Expense	11931000	11920000	4,632.89
503000	Rental Expense	11931000	11920000	1,629.03
505000	Other Operating Exp	11931000	11920000	-
503000	Rental Expense	11931000	11920000	17,623.17
503000	Rental Expense	11931000	11920000	6,196.71
503000	Rental Expense	11931000	11920000	10,861.95
503000	Rental Expense	11931000	11920000	3,819.30
503000	Rental Expense	11931000	11903000	38,338.38
503000	Rental Expense	11931000	11903000	12,500.82
501300	Meals & Ent	11931000	11920000	13,552.60
503000	Rental Expense	11931000	11920000	(17,273.36)
500300	Outside Svs	11931000	11931000	5,590.62
804030	WBS ST Services	11931000	11931000	(5,590.62)
503000	Rental Expense	11931000	11920000	27,953.10
				119,834.59

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500000	Salaries and Wages	11932000	11932000	5,276.07
500300	Outside Svs	11932000	11932000	3,374.46
500300	Outside Svs	11932000	11932000	720.00
500330	Outside Svs-Ser Main	11932000	11932000	796.80
500410	M&C-Small Tools	11932000	11932000	128.27
500430	M&C-Main Parts	11932000	11932000	335.83
500700	Land&Property Rents	11932000	11932000	(4,067.00)
500700	Land&Property Rents	11932000	11932000	4,067.00
500900	Util Exp-Water & Sew	11932000	11932000	(1,805.76)
500900	Util Exp-Water & Sew	11932000	11932000	2,311.84
500910	Util Exp-Waste Remvl	11932000	11932000	750.00
500920	Util Exp-Heat & Elec	11932000	11932000	29,867.99
500940	Util Exp-Gas	11932000	11932000	193.08
502300	Facility Costs	11932000	11932000	(762.00)
502300	Facility Costs	11932000	11932000	172,630.01

502310	Facility Costs-Maint	11932000	11932000	3,189.11
503000	Rental Expense	11932000	11932000	68,933.88
505000	Other Operating Exp	11932000	11932000	4,607.74
505000	Other Operating Exp	11932000	11932000	574.02
505000	Other Operating Exp	11932000	11932000	24.98
505000	Other Operating Exp	11932000	11932000	13,233.90
800000	Lbr Alloc	11932000	11932000	25,833.90
804000	WBS ST Lbr	11932000	11932000	(31,109.97)
804020	WBS ST Material	11932000	11932000	(464.10)
804030	WBS ST Services	11932000	11932000	(4,891.26)
804040	WBS ST Other	11932000	11932000	(293,748.79)
505000	Other Operating Exp	11932000	11920000	-
500910	Util Exp-Waste Remvl	11932000	11932000	1,633.94
502300	Facility Costs	11932000	11932000	19,098.03
804040	WBS ST Other	11932000	11932000	(20,731.97)
				0.00

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Reflected under 4074 but under RR-EN 2-1 9200				
G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
550210	Amort-Rate Bse Offst	11407400	11920000	1,786,846.15
550210	Amort-Rate Bse Offst	11407400	11920000	255,845.53
550210	Amort-Rate Bse Offst	11407400	11920000	303,811.27
550210	Amort-Rate Bse Offst	11407400	11920000	(178,025.58)
550210	Amort-Rate Bse Offst	11407400	11920000	17,440.86
550210	Amort-Rate Bse Offst	11407400	11920000	368.96

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Reflected under 4080 but uner RR-EN 2-1 9260				
G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
500150	Medicare/Healthcare	11408000	11920000	286,382.73
500150	Medicare/Healthcare	11408000	11920000	7,117.65

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Reflect on the annual under 4010 but under 9302 for RR-EN 2-1

G/L Account	G/L Account	Regulatory Acc	Functional Area	12/31/2022
505000	Other Operating Exp	11401000	11920000	49,969.17

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1
Not reflected in RR-EN 2-1

Not reflected in RR-EN 2-1

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-120 September 30, 2021

Petition of Boston Gas Company, doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.

APPEARANCES:

Cheryl M. Kimball, Esq.
Daniel P. Venora, Esq.
Robert J. Humm, Esq.
Jessica Buno Ralston, Esq.
Kerri A. Mahoney, Esq.
99 High Street, Suite 2900
Boston, Massachusetts 02110

-and-

Alexandra E. Blackmore, Esq.
Melissa G. Liazos, Esq.
National Grid USA Service Company, Inc.
40 Sylvan Road
Waltham, Massachusetts 02451
FOR: BOSTON GAS COMPANY
Petitioner

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Joseph W. Rogers
Matthew E. Saunders
Shannon S. Beale
Jacquelyn Bihrle
Donald W. Boecke
Jessica Freedman
Jonathan F. Dinerstein
Ashley Gagnon
Margaret Sullivan
Assistant Attorneys General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Department of Energy Resources
Commonwealth of Massachusetts
Rachel Graham Evans, Esq.
Robert H. Hoaglund II, Esq.
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
Intervenor

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Massachusetts 01930

-and-

Charles Harak, Esq.
Karen Lusson, Esq.
National Consumer Law Center
7 Winthrop Square
Boston, Massachusetts 02110
FOR: THE LOW-INCOME WEATHERIZATION AND FUEL ASSISTANCE PROGRAM NETWORK and THE MASSACHUSETTS ENERGY DIRECTORS ASSOCIATION
Intervenors

Robert Ruddock, Esq.
Ruddock Office
436 Pleasant Street
Belmont, Massachusetts 02478
FOR: THE ENERGY CONSORTIUM
Intervenor

Alfred Gordon O'Connell, Esq.
Pyle Rome Ehrenberg PC
2 Liberty Square, 10th Floor
Boston, Massachusetts 02109
FOR: UNITED STEEL, PAPER AND FORESTRY, RUBBER, MANUFACTURING ENERGY, ALLIED INDUSTRIAL AND SERVICE WORKERS INTERNATIONAL UNION, AFL-CIO
Intervenor

David W. Bogan, Esq.
Stephen Bright, Esq.
Locke Lord LLP
111 Huntington Avenue
Boston, Massachusetts 02199
FOR: DIRECT ENERGY BUSINESS, LLC, DIRECT ENERGY BUSINESS MARKETING, LLC, and DIRECT ENERGY SERVICES, LLC
Intervenors

TABLE OF CONTENTS

I. INTRODUCTION

On November 13, 2020, Boston Gas Company, doing business as National Grid ("National Grid" or "Company") filed a petition with the Department of Public Utilities ("Department") pursuant to G.L. c. 164, § 94, and 220 CMR 5.00 for an increase in its gas base distribution rates to generate $220,736,830 in additional revenues.[1] As part of the filing, the Company proposed to transfer $81,908,027 recovered through the gas system enhancement program ("GSEP") to base distribution rates, effective October 1, 2021. Because there is a delay in recovery through the GSEP, however, the Company proposed to not fully recover the remaining balance in the GSEP until May 1, 2022. Based on these GSEP-related proposals, the Company initially requested an overall increase of $138,828,803 to distribution revenues, which the Company stated represents an 18.1 percent incremental increase in distribution revenue. Based on changes made during the proceeding, National Grid now proposes a general increase in base distribution rates of $219,007,760, a transfer of $81,180,455 in revenues recovered through the GSEP, and an overall net increase of $137,827,305 (Exhs. NG-RRP-2, Sch. 1, at 1-3 (Rev. 3); NG-PP-6(b) (Rev. 3)).[2]

The Company also proposes to implement a performance-based ratemaking ("PBR") mechanism that would allow National Grid to adjust its base distribution rates on an annual

---

[1] The Company filed for approval of tariffs M.D.P.U. Nos. 1.17, 2.4, 3.13, 4.4, 5.6, and 27 through 57 (Exh. NG-PP-10).

[2] Minor discrepancies in any of the amounts appearing in this Order are due to rounding.

basis through the application of a revenue-cap formula and to put in place a set of metrics to evaluate the Company's performance (Exh. NG-MLR-1, at 5). National Grid proposes to implement the PBR plan for five years with the possibility for extension, and to implement a set of performance incentive mechanisms and metrics to evaluate the Company's performance during the PBR plan's term (Exh. NG-MLR-1, at 5).[3]

National Grid bases its proposed base distribution rate increase on a split test year of April 1, 2019 through March 31, 2020 (Exh. NG-MLR-1, at 6). National Grid was last granted an increase in electric base distribution rates in 2018. Boston Gas Company/Colonial Gas Company, D.P.U. 17-170 (2018).[4] The Department docketed the instant petition as

3 National Grid's filing also contained four proposed demonstration programs that the Company stated were intended to further the Commonwealth's greenhouse gas emissions goals: (1) a proposed Gas Demand Response demonstration program targeting gas constrained areas; (2) a proposed Geothermal District Energy demonstration program; (3) a proposed Hydrogen demonstration program using existing natural gas networks; and (4) a proposed Renewable Natural Gas ("RNG") demonstration program to enable RNG interconnections and RNG procurement. On December 11, 2020, the Department issued an Interlocutory Order and removed these proposed demonstration programs from consideration in this docket. D.P.U. 20-120, Interlocutory Order on Proposed Demonstration Programs (December 11, 2020). On February 18, 2021, the Company refiled its Geothermal District Energy demonstration program proposal, which the Department docketed as D.P.U. 21-24. That matter still is pending before the Department.

4 On December 19, 2019, the Department approved a merger of Boston Gas and Colonial Gas Company. Boston Gas Company/Colonial Gas Company, D.P.U. 19-69 (2019). The merger was effective on March 15, 2020.

D.P.U. 20-120 and suspended the effective date of the tariffs until October 1, 2021, for further investigation.[5]

National Grid provides retail gas distribution service to over 930,000 customers in 144 cities and towns in Massachusetts (Exh. NG-MLR-1, at 22). The Company operates as wholly owned subsidiary of National Grid USA, which is an indirect wholly owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales (Exhs. NG-MLR-1, at 21-22; AG 1-98, Att. at 2).[6] National Grid USA also owns National Grid USA Service Company ("NGSC"), which provides management, administrative, accounting, legal, engineering, information systems, and other services to National Grid USA subsidiaries, including the Company (Exhs. NG-RRP-1, at 1; AG 1-26, Att. 1, at 41-42; AG 1-98, Att. at 1). In addition to the Company, at the time of the filing of the instant petition, National Grid plc also indirectly owned affiliated electric and gas distribution companies operating in Rhode Island and New York (Exh. NG-MLR-1, at 22).[7]

5 While the Company requests that the new base distribution rates be effective October 1, 2021, it seeks to implement the new rates effective November 1, 2021 (Exh. NG-PP-1, at 56). The Company would recover the incremental base distribution revenue accrued for the first month of the rate year through the revenue decoupling adjustment factors (Exh. NG-PP-1, at 66-67).

6 National Grid plc owns and operates electric transmission and gas transmission and distribution networks in the United Kingdom (Exh. NG-MLR-1, at 22).

7 Pursuant to a Share Purchase Agreement, executed on March 17, 2021, National Grid USA agreed to sell its outstanding common stock ownership in its Rhode Island operation utility, Narragansett Electric Company, to PPL Rhode Island Holdings, LLC. On July 16, 2021, the Department determined that the transaction would have no adverse impacts on National Grid USA's Massachusetts companies or their ratepayers. National Grid USA, D.P.U. 21-60, at 38-39 (July 16, 2021). As such,

On November 17, 2020, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E.[8] On December 16, 2020, the Department granted the petition to intervene as a full party filed by the Massachusetts Department of Energy Resources ("DOER"). On December 18, 2020, the Department granted the petitions to intervene as full parties of: (1) the Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association; and (2) The Energy Consortium. On December 21, 2020, the Department granted the petition to intervene as a full party filed by Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, and Direct Energy Services, LLC (collectively "Direct Energy"). Finally, on December 22, 2020, the Department granted the petition to intervene as a full party filed by United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union,

---

the Department granted National Grid USA's request for a waiver from the requirements of G.L. c.164, § 96(c). D.P.U. 21-60, at 39. On August 12, 2021, the Attorney General appealed the Department's decision to the Supreme Judicial Court. Docket No. SJ-2021-0305.

8 On December 22, 2020, the Department approved the Attorney General's retention of experts and consultants, filed pursuant to G.L. c. 12, § 11E(b), to assist her in representing consumer interests in this case at a cost not to exceed $550,000. D.P.U. 20-120, Order on Attorney General's Notice of Retention of Experts and Consultants (December 22, 2020). The costs incurred by the Attorney General in this proceeding are reimbursed by National Grid, and the Company then passes these costs on to ratepayers. D.P.U. 17-170, at 3 n.3, citing Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-55, at 425-426 (2010).

AFL-CIO, by and on behalf of its constituent Locals 12003, 12012-4, and 13507 (collectively, "USW").

Pursuant to notice duly issued, and in accordance with the COVID-19 state of emergency issued by Governor Baker on March 10, 2020,[9] the Department held virtual public hearings on January 26, 2021 and January 28, 2021.[10] The Department held 13 days of virtual evidentiary hearings from May 4, 2021 through May 26, 2021.

In support of its filing, National Grid sponsored the testimony of the following witnesses, all of whom were employed by NGSC: (1) Marcy L. Reed, president of Massachusetts jurisdiction and executive vice president of U.S. policy and social impact;[11] (2) William Malee, vice president, regulation and pricing, New England; (3) Christopher McCusker, controller, New England and Federal Energy Regulatory Commission ("FERC"); (4) Ian M. Springsteel, director of U.S. retail regulatory strategy; (5) Sharon S. Daly, lead analyst, U.S. retail regulatory strategy group; (6) Maureen P. Heaphy, vice president of

---

9 On March 10, 2020, Governor Baker issued an Executive Order declaring a state of emergency regarding COVID-19, a contagious and, at times, fatal respiratory disease. See Executive Order No. 591: Declaration of a State of Emergency to Respond to COVID-19, dated March 10, 2020 and available at: https://www.mass.gov/doc/governors-declaration-of-emergency-march-10-2020-aka-executive-order-591/download (last visited March 22, 2021).

10 The Department received oral and written comments during the public comment period.

11 On March 19, 2021, National Grid notified the Department that, because of Ms. Reed's impending retirement, her testimony, supporting exhibits and responses to information requests would be adopted by Terence Sobolewski, the interim president of the Massachusetts jurisdiction at NGSC.

U.S. compensation, benefits, and pensions; (7) Krishna Seetharam, the chief information officer for New York; (8) Robert Lorkiewicz, the chief information officer for New England; (9) Stephen R. Olive, senior vice president and U.S. chief information officer;[12] (10) Daniel J. DeMauro, director of information technology ("IT") regulatory; (11) Christopher Murphy, vice president, U.S. chief information security officer, and head of cyber security engineering; (12) Ross W. Turrini, senior vice president for gas process and chief gas engineer; (13) Mark L. Prewitt, vice president of gas pipeline safety and compliance; (14) Caroline Hon, chief operating officer for New England gas business; (15) Amy F. Soloman, lead analyst in the New England revenue requirements, regulation and pricing department; (16) Michael J. Pini, lead program manager in the New England revenue requirements, regulation and pricing department; (17) Paula M. Leaverton, manager of U.S. property tax; (18) Elizabeth Arangio, director of gas supply planning; (19) Amy Smith, director of New England jurisdiction; and (20) Pamela Bushmich, director of U.S. tax department.[13,14] National Grid also sponsored the testimony of the following external

---

12 On March 19, 2021, National Grid notified the Department that, because of Mr. Olive's impending departure from the Company, his testimony, supporting exhibits, and responses to information requests would be adopted by Mr. Seetharam and Mr. Lorkiewicz, both of whom also provided their own joint testimony.

13 During evidentiary hearings, National Grid made the following NGSC employees, who had not submitted written testimony, available for cross examination: (1) Jeffrey Martin, director of customer operations; and (2) Christopher McConnachie, chief financial officer for New York.

14 The Company also sponsored the testimony of two additional NGSC employees: (1) Owen Brady-Traczyk, the manager of the future of heat team in the customer organization at NGSC; and (2) Lee Gresham, Ph.D., the lead analyst of the future of

consultant witnesses: (1) Mark E. Meitzen, Ph.D., senior consultant at Christensen Associates; (2) Nicholas A. Crowley, economist at Christensen Associates; (3) Lawrence R. Kaufmann, Ph.D., president of LKaufmann Consulting, Inc. and senior advisor to Pacific Economics Group Research LLC and to Navigant Consulting; (4) Ned W. Allis, consultant, Gannett Fleming Valuation and Rate Consultants, LLC; (5) Ann E. Bulkley, senior vice president at Concentric Energy Advisors, Inc.; (6) Melissa F. Bartos, vice president at Concentric Energy Advisors, Inc.; (7) Gregg M. Therrien, manager of U.S. property tax at Concentric Energy Advisors, Inc.; (8) Bickey Rimal, senior project manager at Concentric Energy Advisors, Inc.; and (9) Daniel D. Dane, senior vice president at Concentric Energy Advisors, Inc. and financial and operations principal of CE Capital, Inc.

The Attorney General sponsored the testimony of the following witnesses: (1) Benjamin W. Griffiths, energy advisor in the energy and telecommunications division at the Attorney General's office; (2) David J. Effron, consultant; (3) David J. Garrett, managing member of Resolve Utility Consulting, PLLC; (4) J. Randall Woolridge, professor of finance at Pennsylvania State University; (5) Scott J. Rubin, consultant; (6) David E. Dismukes, Ph.D., consulting economist at Acadian Consulting Group; (7) John Rodney Walker, chief executive officer and president of Rod Walker & Associates Consultancy, Inc.; (8) Brian MacLean, associate at Rod Walker & Associates Consultancy, Inc.; (9) Dan

---

heat team within the regulatory and customer strategy departments at NGSC. These witnesses provided prefiled testimony on the Company's four proposed demonstration programs, which, as noted in n.3 above, were removed from consideration in this proceeding.

Lambright, associate at Rod Walker & Associates Consultancy, Inc.; (10) John Defever, regulatory consultant at Larkin & Associates, PLLC; and (11) Frank W. Radigan, principal at Hudson River Energy Group.

On June 17, 2021, the Attorney General, DOER, and TEC submitted initial briefs. On July 2, 2021, National Grid submitted its initial brief. On July 19, 2021, the Attorney General, DOER and TEC submitted reply briefs. On July 28, 2021, National Grid submitted its reply brief. The evidentiary record consists of approximately 4,000 exhibits and responses to 76 record requests.

II. COMPANY'S USE OF A SPLIT TEST YEAR

A. Introduction

The revenue requirement component of the Company's filing is based on a test year ending March 31, 2020, representing a non-calendar or split test year (Exh. NG-RRP-1, at 10).[15] Non-calendar test years have, on occasion, been accepted by the Department. See, e.g., NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at 25-28 (2017); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 21-22 (2016); Plymouth Water Company, D.P.U. 14-120, at 16 (2015); Milford Water Company, D.P.U. 12-86, at 1 (2013). However, the

15 A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. NSTAR Gas Company, D.P.U. 14-150, at 45 n.26 (2015); Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015). A test year, whether a calendar year test year or a "split" test year, comprises a period of twelve consecutive calendar months.

Department has expressed its strong preference for a calendar year test year and has noted that any company that seeks to rely on a split test year faces a high burden to demonstrate as a threshold matter that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16 & n.11.

In support of its split test-year filing, the Company provided audited financial statements for the fiscal years ended March 31, 2018, March 31, 2019, and March 31, 2020 (Exhs. NG-RRP-1, at 12; WP NG-RRP-1, at 35-74). These audited financial statements include the recognition of accruals booked to reserve accounts and end-of-period reconciliations for those account balances (Exhs. NG-RRP-1, at 12; WP NG-RRP-1). The Company also provided certain schedules found in the annual returns to the Department incorporating data as of March 31, 2019, and March 31, 2020, consisting of a balance sheet, statement of income, statement of earned surplus, and gas operations and maintenance expenses for both Boston Gas and the former Colonial Gas (Exhs. NG-RRP-1, at 12; WP NG-RPP-1, at 2-34). Finally, the Company provided a reconciliation of key income and balance sheet accounts to its audited financial statements (Exhs. NG-RRP-1, at 13; WP NG-RRP-1, at 1).

B. Attorney General Analysis

While the Attorney General does not contest National Grid's use of a split test year on brief, she provided initial testimony that raised concerns about the reviewability of the Company's charges from NGSC (Exh. AG-JD-11, at 11-12). According to the Attorney General, during the test year, the Company booked $162,709,309 in charges from NGSC, organized into NCSC's 22 functional cost centers (Exhs. AG-JD-1, at 12-13; AG 2-5, Atts.).[16] The Attorney General states that while the Company provided its historical NGSC charges by current functional cost centers for both the fiscal year and calendar years 2015 through 2020, it did not provide comparable amounts for either the adjusted test year or the rate year (Exh. AG-JD-1, at 11, citing Exh. AG 2-5, Atts.). The Attorney General considers this lack of information to significantly impede attempts to determine whether the requested rate year NGSC charges are reasonable, particularly in light of the significant level of NGSC expense and annual increases (Exh. AG-JD-1, at 12, citing Exh. AG 2-5, Att.). The Attorney General notes that because costs by functional cost center have fluctuated from year to year, there could be some nonrecurring expenses embedded in the Company's test-year NGSC charges (Exh. AG-JD-1, at 13).

C. Positions of the Parties

The Company argues that it has provided information supporting its proposed test year in the form of audited financial statements, accruals with end-of-period reconciliations, pro forma key schedules, and a reconciliation of its audited financial statements to its

---

16 NGSC's cost allocation manual was most recently revised in 2020 (Exh. AG 2-3, Att. 1). The Company incurs NGSC charges from the following functional cost centers: (1) Audit; (2) Business Services; (3) Capital Delivery; (4) Corporate Affairs; (5) Customer Operations; (6) Electric Business Unit; (7) Executive Director US; (8) Finance; (9) Gas Business Unit; (10) Human Resources; (11) Information Technology; (12) Legal; (13) Massachusetts Jurisdiction; (14) National Grid Ventures Jurisdiction; (15) New York Jurisdiction; (16) Other Actuals; (17) Procurement; (18) Safety; (19) Health & Environment; (20) Strategy & Regulation; (21) Transformation Office; and (22) Transmission, Generation and Energy Procurement (Exh. AG 2-5, Atts.).

pro forma annual report (Company Brief at 85-86, citing Exhs. NG-RRP-1, at 12-13; WP NG-RRP-1). The Company contends that its proposed test year is thus reviewable and reliable and represents a full accounting of its operations for the period (Company Brief at 86). No intervenor addressed the Company's proposed split test year on brief.

D. Analysis and Findings

It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45 (2015); Investigation into Rate Structures that Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 52-53 (2008); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); see also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to Section 94, the Department examines a test year on the basis that the revenue and expense figures adjusted for known and measurable changes, and rate base figures during that period, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. D.P.U. 14-120, at 9; see Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 145-146 (2016), citing D.P.U. 07-50-A at 51; Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984). The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case unless there are extraordinary circumstances that render a previous Order confiscatory. D.P.U. 14-150, at 45 n.26; Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. D.P.U. 14-150, at 45 n.26; Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24, cert. denied, 439 U.S. 921 (1978).

As noted above, the Department has expressed strong preference for a test-year cost of service based on a calendar year as opposed to a split test year. D.P.U. 14-120, at 12, 16; see also D.P.U. 14-150, at 45 n.26. Although the Department has, on occasion as noted above, accepted a non-calendar test year, we also have recognized that there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates. D.P.U. 14-120, at 10; see AT&T Communications of New England, Inc., D.P.U. 90-133-A at 5-6 (1991). For example, test-year amounts associated with a split test year will not tie back to amounts included in the annual returns submitted to the Department, which are prepared on a calendar-year basis. D.P.U. 17-05, at 23; D.P.U. 15-155, at 14-15; D.P.U. 14-120, at 11. The use of a split test year also limits the Department's ability to review year-to-year changes in expense levels. D.P.U. 17-05, at 23; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11. This limitation is of significant concern to the Department because reliance on a split test year may create an improper incentive for utilities to book expenses into a certain time period for purposes of creating an inflated test-year expense. D.P.U. 17-05, at 23-24; D.P.U. 15-155, at 15;

D.P.U. 14-120, at 11. Another complication associated with use of a split test year involves year-end accounting for accrued revenues and expenses which, if not properly recognized in the rate-setting process, may result in a distorted measurement of net operations. D.P.U. 17-05, at 24; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11; see The Berkshire Gas Company, D.P.U. 1490, at 35-37 (1983).

It also is well established that the burden is with a company to satisfy the Department that the company's proposal will result in just and reasonable rates. D.P.U. 17-05, at 24; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11-12; New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.T.E. 03-40, at 52 n.31 (2003), citing The Berkshire Gas Company, D.T.E. 01-56-A at 16 (2002); Boston Gas Company, D.P.U. 93-60, at 212 (1993); Blackstone Gas Company, D.P.U. 19579, at 2-3 (1978).[17] Therefore, given the importance of the concerns discussed above and their significance for ratepayers, the Department affirms its very clear preference to use an historic calendar year test year to establish rates. D.P.U. 17-05, at 24; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11-12.

The Department has noted that any decision to rely on a non-calendar test year will carry with it a high burden for a company to demonstrate that its proposed rates are just and reasonable. D.P.U. 17-05, at 24; D.P.U. 15-155, at 15-16; D.P.U. 14-120, at 12.

---

[17] That the burden of proof is always with those who take the affirmative in pleading is a long-held tenet in Massachusetts jurisprudence. Phelps v. Hartwell, 1 Mass. 71, 73 (1804).

Specifically, any company that seeks to rely on a split test year, as a threshold matter, must demonstrate by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 17-05, at 24-35; D.P.U. 15-155, at 16; D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 4-14 (1976). Further, at a minimum, a company that proposes to use a split test year must be prepared to make a threshold showing:

(1) how its test-year account balances tie back to the account balances as reported in the annual returns;

(2) that the amounts have been properly audited (or, in the case of a small water company that is not a subsidiary of a publicly traded entity, otherwise verified) and are available for review;

(3) that a meaningful year-to-year review of changes in expense levels and revenues is possible, such that the Department can determine whether the company's test-year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability; and

(4) that the company has properly recognized accruals booked to reserve accounts, including any end-of-period reconciliations of those account balances.

D.P.U. 17-05, at 25; D.P.U. 15-155, at 16; D.P.U. 14-120, at 6 n.11.

Based on our review of the Company's filing and the account level detail provided by the Company, we find that it is possible to tie the Company's test-year account balances back to the account balances as reported in its annual returns. See D.P.U. 14-120, at 16 n.11. First, the Company provided balance sheets, income statements, statements of earned surplus, and gas operations and maintenance expense schedules corresponding to those same schedules provided in the annual returns to the Department, incorporating data as of March 31, 2019, and March 31, 2020, for both Boston Gas and the former Colonial Gas (Exhs. NG-RRP-1, at 12; WP NG-RRP-1, at 2-34). The Company has also provided documentation mapping the accounts maintained in its internal accounting system to the accounts reported in the annual returns to the Department in accordance with the Department's Uniform System of Accounts for Gas Companies (RR-DPU-3).[18] The Department has examined these schedules and is satisfied that the information is sufficient to tie the Company's test-year account balances back to its annual returns.

Further, the Company's audited financial statements prepared by Deloitte & Touche are based on the Company's fiscal year ending March 31, which corresponds to the March 31, 2020, end of the test year proposed here (Exh. AG 1-2, Atts. 1 through 8 & Supps.). On this basis, the Department finds that the audited financial statements provide an independent and extensive review of the Company's test-year cost of service data, and thus clearly satisfies the D.P.U. 14-120 threshold showing. In reaching this finding, the Department notes that financial audits are designed to show whether the subject of the audit has properly prepared its financial statements to be free of material misstatements and to

---

18 The Company's internal account numbers are based on an alphanumeric system of "natural accounts" (i.e., groupings of various accounts by function) (Exh. AG 1-34, Atts. 4 through 6; Tr. 1, at 93; RR-DPU-3). While gas companies are permitted to use their own accounting systems for financial reporting purposes, they are required to report to the Department based on the Uniform System of Accounts for Gas Companies. 220 CMR 50.00, General Instruction 1, Form of Books and Accounts Prescribed. A company that maintains a different accounting system is required to maintain a list reconciling the accounts and subaccounts it uses with those required by the Department. 220 CMR 50.00, General Instruction 1, Form of Books and Accounts Prescribed.

express an opinion on the subject's internal controls. While audited financial statements are of considerable assistance in the ratemaking process, an audit does not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded to such costs. See Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240, Introductory Letter (May 19, 1941). See also Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997). The Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in the specific sections of this Order that follow.

In addition, the Department has examined the Company's revenues and expenses, including comparisons of expenses booked during the first three months of 2019 versus those booked during the first three months of 2020 (Exhs. WP NG-RRP-1, at 8-12; DPU 49-7; DPU 49-8; DPU 49-9; DPU 49-10; DPU 49-11; DPU 49-12; DPU 49-13; DPU 49-14). Some year-to-year variation is expected, even when comparing individual functions and accounts over corresponding time periods (Exhs. WP NG-RRP-1, at 8-12; AG 1-34, Atts. 4 through 6; AG 2-5, Atts.; AG 2-6, Atts.). The Company attributes the most significant variations between the first three months of 2019 and the first three months of 2020 to expenditures incurred in connection with work continuation plans necessitated by the June 2018 to January 2019 strike (Exhs. DPU 49-7; DPU 49-8; DPU 49-9; DPU 49-10; DPU 49-11; DPU 49-12; DPU 49-13; DPU 49-14; AG 2-5). Other factors include expenses related to the COVID-19 pandemic, the roll-out of the Company's Agent Interaction

Management System ("AIMS")[19] in May 2019, and a reversal of prior period charges from the American Gas Association during the first quarter of 2019 (Exhs. DPU 49-13; DPU 49-14). The Company's COVID-19 expenses were partially offset by a reduction of approximately $2.4 million in information technology expenses driven by a one-time credit of $731,723 from Verizon New England, Inc. ("Verizon")[20] and the reclassification of approximately $491,000 in labor-related costs associated with two of NGSC's IT projects from expense to construction work in progress ("CWIP") (Exhs. NG-RRP-1, at 71; DPU 49-14; AG 37-1, Att. 3, at 2; Tr. 1, at 96; Tr. 8, at 977-978; RR-DPU-4).

As noted above, the Attorney General expresses her concern that the Company's failure to provide its adjusted test-year rate-year NGSC costs by functional cost center (e.g., audit, legal, procurement) significantly impedes her evaluation of those costs for reasonableness and whether there are nonrecurring reasons for their year-to-year fluctuations (Exh. AG-JD-1, at 12-14). While comparisons by functional cost centers are useful in the regulatory process, the Company's revenue requirement calculations are not dependent upon cost centers, but on account balances and expense categories (Exhs. AG 27-3; AG 44-2). In order to provide adjusted test-year and rate-year information for NGSC's functional cost center categories, the Company would have to perform complex calculations requiring a number of assumptions to develop adjusted test-year and rate-year expense levels for each

---

[19] AIMS is a telecommunications platform for toll-free and Voice over Internet Protocol (Exh. DPU 49-13).

[20] The Verizon credit is addressed in Section VIII.K below.

functional cost center (Exhs. NG-RRP-Rebuttal-1, at 15-16; AG 2-5 & Atts.; AG 27-3). Those same adjustments may also need to be performed on historical expenses in order to provide a proper basis of comparison. The probative value of such an exercise to determine whether a particular test-year expense is representative is unclear.

Moreover, the Department does not consider it necessary to identify adjusted test-year and rate-year expenses by functional cost center. The Department has frequently been called upon to evaluate a company's historic and test-year expenses to identify whether they are representative of its ongoing costs, without the need to identify their adjusted test-year or rate-year expense levels. D.P.U. 15-80/D.P.U. 15-81, at 141-143; D.P.U. 12-86, at 126-127, 129-131, 150-151; Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-55, at 287-297, 434-445 (2010); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 146-149 (2009); New England Gas Company, D.P.U. 08-35, at 120-125 (2009); Housatonic Water Works Company, D.P.U. 86-235, at 10-13 (1986); Milford Water Company, D.P.U. 771, at 16 (1982). Therefore, the Department finds it unnecessary to require the Company to itemize its adjusted test-year expenses or pro forma expense by functional cost center as proposed by the Attorney General.

Based on our review, we conclude that the aforementioned information allows for a meaningful review of year-to-year changes in expense levels in order to determine whether the Company's test-year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability. See

D.P.U. 14-120, at 16 n.11. To the extent any test-year revenues and expenses are found to be unrepresentative or unreasonable, the Department will consider the appropriate ratemaking treatment in the specific sections of this Order that follow.

Finally, the Department has examined the Company's accruals booked to reserve accounts and end-of-period reconciliations, as well as the Company's accounting policies (Exhs. WP NG-RRP-1; DPU 22-1 & Atts.; DPU 22-2 & Atts.). The Company's accruals are booked in accordance with National Grid USA's Accounting Policy US AP 305.01.2 Accrued Liabilities ("AP 305")[21] (Exh. DPU 22-1, Att. 3). All accounts are reconciled in accordance with National Grid USA's Account Reconciliations Policy US AP 800.05.1, which provides for various review and approval procedures (Exh. DPU 22-2, Att. 7). Based on our review, we find that the Company has demonstrated that it properly recognized its accruals booked to reserve accounts, including its end of period reconciliations. See D.P.U. 14-120, at 16 n.11. To the extent any adjustments associated with accrual accounts are warranted, the Department will consider the appropriate ratemaking treatment in the specific sections of this Order that follow.

---

[21] Because National Grid USA's parent is a British corporation, AP 305 generally adheres to the requirements of International Financial Reporting Standards, with several exceptions where generally accepted accounting principles are applied (Exh. DPU 22-1, Att. 3, at 2, 5-6). Notwithstanding these financial reporting standards, the Company's regulatory accounting is subject to the Department's oversight and relies on the Uniform System of Accounts for Gas Companies. 220 CMR 52.00, General Instruction 1; Bay State Gas Company, D.P.U. 12-25, at 235 n.144 (2012).

Based on the above considerations, the Department finds that the Company has satisfied the split test-year threshold requirements set forth in D.P.U. 14-120 and has demonstrated that its financial data is reviewable and reliable and represents a full accounting of the Company's operations for the test-year period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Therefore, we conclude that there is sufficient reviewable and reliable information in the record to evaluate the Company's filing based on a test year for the twelve months ending March 31, 2020. As noted above, the Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in the specific sections of this Order that follow.

Finally, we emphasize that our findings here are limited to the specific facts and circumstances of this case and in no way change the Department's clear preference for companies to use a calendar year test year as the norm. D.P.U. 17-05, at 28; D.P.U. 15-155, at 22; D.P.U. 14-120, at 6. We reiterate that any company that seeks to rely on a split test year must, at a minimum threshold level, make a prima facie showing by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 17-05, at 28; D.P.U. 15-155, at 22; D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Failure to make such a robust showing will result in dismissal of the company's rate proceeding.

III. LEDGER CONSOLIDATION

A. Introduction

As part of the Company's merger with the former Colonial Gas, Boston Gas assented to a proposal by the Attorney General that the merged companies continue to maintain separate records and file separate annual returns for Boston Gas and the former Colonial Gas until otherwise ordered by the Department. Boston Gas Company/Colonial Gas Company, D.P.U. 19-69, at 5 (2019). Consequently, the Company maintains separate accounting records and files separate annual returns for Boston Gas and the former Colonial Gas (Exhs. NG-RRP-1, at 6; AG 1-2, Atts. 15, 17; AG 1-2, Atts. 1 & 2 (Supp.)).

The Company's revenue requirement was prepared on a consolidated basis for both Boston Gas and the former Colonial Gas (Exhs. NG-RRP-1, at 8-9; NG-RRP-2, Sch. 1). In preparing its consolidated revenue requirement, the Company states that it may be difficult to maintain the reliability of separate financial statements for its legacy systems over the five-year term of its proposed PBR plan (Exh. NG-RRP-1, at 8). Consequently, the Company requested that the Department authorize it to consolidate the accounting records of Boston Gas and the former Colonial Gas after the conclusion of this proceeding (Exh. NG-RRP-1, at 7-8; Tr. 1, at 131-133).

B. Positions of the Parties

The Company justifies the use of a combined revenue requirement on the basis that since the merger of the former Colonial Gas with Boston Gas, it has operated as a single entity on a fully integrated basis, and that filing separate revenue requirements would be inconsistent with this status and the manner in which the legacy companies are operated and managed (Company Brief at 83, citing Exh. NG-RRP-1, at 8-9). The Company also maintains that a combined revenue requirement is warranted because it may be difficult to maintain the reliability of separate financial statements for Boston Gas and the former Colonial Gas over the five-year term of its proposed PBR (Company Brief at 83, citing Exh. NG-RRP-1, at 5, 8). No intervenor addressed the Company's proposed journal consolidation on brief.

C. Analysis and Findings

Gas and electric companies engaged in the manufacture and sale or distribution of gas or electricity are required to keep their books and accounts in a form prescribed by the Department. G.L. c. 164, § 81; 220 CMR 50.00, 51.00, 52.00. The Department may require that a company maintain certain records and accounting practices. Fryer v. Department of Public Utilities, 374 Mass. 85 (1978). These companies also are required to furnish a return annually to the Department, in a form prescribed by it. G.L. c. 164, § 83; D.P.U. 17-05, at 45. The Department has previously required merging companies that intend to maintain their existing rate structures to maintain separate financial records in order to allow for proper identification of costs between multiple service areas.[22] D.P.U. 19-69,

[22] The Department has observed that the failure to maintain separate accounts will, over time, eliminate rate differentials between separate service areas by virtue of the lack of reliable cost data. Bay State Gas Company/Brockton-Taunton Gas Company, D.P.U. 18133, at 5 (1974). Rate consolidation, if such is to be permitted in the future, should be based on substantial evidence, rather than necessitated by default. D.P.U. 17-05, at 45 n.22.

at 12; D.P.U. 17-05, at 45; Bay State Gas Company/Brockton-Taunton Gas Company, D.P.U. 18133, at 5 (1974). While the Department approved National Grid's proposal to maintain separate annual returns for Boston Gas and the former Colonial Gas, it has not otherwise required companies to maintain separate annual returns by legacy companies as a condition of a merger. D.P.U. 19-69, at 12; D.P.U. 17-05, at 45-46.[23]

We first turn to the issue of maintaining separate annual returns for Boston Gas and the former Colonial Gas. Colonial Gas' corporate existence was extinguished on March 15, 2020, upon the corporate consolidation of Boston Gas and Colonial Gas. Nevertheless, the Company voluntarily agreed to file separate annual returns for its legacy systems. D.P.U. 19-69, at 5.

Maintaining separate annual returns for legacy companies is unnecessary for cost allocation or rate-design purposes, as evidenced by Boston Gas' ability to maintain separate cost allocations and rate structures associated with its legacy Essex Gas Company operations acquired in 2010 and other legacy operations acquired during the early 1970s, as well as Colonial Gas' use of separate cost allocations and rate structures for its own legacy Lowell and Cape Cod divisions. D.P.U. 17-170, at 355-373; Colonial Gas Company, D.P.U. 86-27-A at 19-85 (1988); Boston Gas Company, D.P.U. 17885, at 4-5 (1974). Other utilities have been able to develop cost allocations for their legacy companies without

23 In cases involving the acquisition of operating companies by a holding company, however, the operating companies remain in existence and thus remain obligated to file separate annual returns. G.L. c. 164, § 83.

the need to prepare multiple annual returns. Massachusetts-American Water Company, D.P.U. 453, at 11-12 (1982).[24] Finally, Department records indicate that other companies engaged in merger and acquisition activities have relied on zone-based rates without the need to submit separate annual returns for the legacy companies, such as Bay State Gas Company after its acquisition of Lawrence Gas Company in 1976, Worcester Gas Light Company after its acquisition of Cambridge Gas Company in 1971, The Berkshire Gas Company after its acquisition of Greenfield Gas Light Company in 1958, and Massachusetts Electric Company after its formation from seven affiliated electric companies in 1960. Bay State Gas Company/Lawrence Gas Company, D.P.U. 18620 (1976); Worcester Gas Light Company/Cambridge Gas Company, D.P.U. 17140 (1971); The Berkshire Gas Company/Greenfield Gas Light Company, D.P.U. 12479 (1958); Worcester County Electric Company, et al., D.P.U. 13473 (1960).

This ability to forgo multiple annual returns exists because the information required for cost allocation and rate design is not only derived from a company's annual returns, but from a combination of direct assignment and various allocation factors (Exh. NG-PP-5, at 1-5). See also NSTAR Gas Company, D.P.U. 19-120, at 413-423 (2020); Massachusetts

---

[24] While Southern Union Company filed separate annual returns for its North Attleboro and Fall River divisions between 2001 and 2008, this practice was adopted by that company in furtherance of its business plan to operate the two divisions as separate entities. See Southern Union/Fall River Merger, D.T.E. 00-25, at 2 (2000); Southern Union/North Attleboro Merger, D.T.E. 00-26, at 2 (2000). At that time, Southern Union Company was a multi-state corporation engaged in distribution, gathering, processing, transportation, and storage of natural gas.

Electric Company and Nantucket Electric Company, D.P.U. 18-150, at 507-511 (2018); D.P.U. 17-05-B at 25-27; Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 293-300 (2009). These allocation factors are derived from both internal and external sources and are not limited to information provided in an annual return.

Based on these considerations, the Department concludes that filing separate annual returns for Boston Gas and the former Colonial Gas is unwarranted and unnecessary for cost allocation purposes. In light of the fact that annual returns for both operations have been filed for the year 2020, the Department orders the Company to file its first combined annual return using calendar year 2021.

We now turn to the Company's maintenance of separate financial records for Boston Gas and the former Colonial Gas. National Grid uses a separate company code and name in its integrated software system ("SAP")[25] financial system for its former Colonial Gas, thus allowing for the generation of standalone financial statements and other reports for the former Colonial Gas (Exhs. NG-RRP-1, at 7; DPU 22-3; DPU 22-4; DPU 22-5). The Department emphasizes the importance of a robust written documentation process describing the procedures that National Grid uses to allocate costs between its legacy companies, both to facilitate Department and intervenor review of these allocations and to allay any concerns that National Grid's cost-allocation process contains errors or are based on result-driven outcomes. See D.P.U. 10-114, at 200-201.

---

[25] SAP is an accounting, financial, general ledger, and human resources system used by National Grid since 2012. D.P.U. 17-170, at 55 & n.35.

Notwithstanding National Grid's efforts to maintain separate accounting for Boston Gas and the former Colonial Gas, there are a number of challenges in maintaining such a system. For example, while employees of the former Colonial Gas are now employees of Boston Gas, they continue to charge their costs to the former Colonial Gas (Exhs. NG-RRP-1, at 7; DPU 22-3).[26] Similarly, NGSC employees and employees of other National Grid affiliates charge their costs as if the merger had not occurred (Exhs. NG-RRP-1, at 7-8; DPU 22-3). Despite these procedures, however, factors such as employee attrition, employee job changes, and department reorganizations that occur over time will make it more difficult to ensure that the costs charged to National Grid's Massachusetts gas operations are appropriately segregated as being related to Boston Gas or the former Colonial Gas (Exh. NG-RRP-1, at 8).

Similar complexities are already associated with accounting for the Company's balance sheet items. Although the infrastructure in the former Colonial Gas service territory can be readily identified, other balance sheet items are less amenable to disaggregation. For example, any debt issuance to support plant investment must be made in the name of Boston Gas because Colonial Gas has ceased to exist as a corporate entity (Exh. NG-MLR-1, at 1; Tr. 1, at 101). Consequently, balance sheet components such as debt issuances and equity infusions in the form of shareholder contributions must be apportioned between the legacy

---

26 The Company states that subject to union considerations, it will be more administratively efficient to enable employees who currently are limited to working in the legacy service areas to work in either service area on an interchangeable basis (Exh. NG-RRP-1, at 9).

systems through either the Company's Treasury Management System ("TMS") or manual journal entries (Exhs. DPU 22-4; DPU 22-5).[27]

Similarly, in the case of future long-term capital contributions from its parent company, the Company states that it will initially record equity infusions to Boston Gas through manual journal entries, then apply the appropriate accounting entries for Boston Gas or the former Colonial Gas onto the general ledger in the form of either an equity contribution or intercompany payable (Exh. DPU 22-5; Tr. 1, at 100-102). Although National Grid referenced the need for subsidiary accounting adjustments for the use of equity contribution or intercompany payable accounts, the Company has not yet finalized its apportionment of these capital infusions for reporting purposes (Tr. 1, at 99-102; Tr. 8, at 976).[28]

In this instance, the Department finds that the potential benefits of maintaining separate accounts for Boston Gas and the former Colonial Gas in the form of more precise cost allocators are outweighed by the inherent difficulties associated with maintaining separate

---

27 Because the Company's current TMS is limited to a one-to-one relationship between itself and the counterparty (i.e., lender), the Company is investigating whether its TMS can be configured to allocate future debt issuances between Boston Gas and the former Colonial Gas (Exh. DPU 22-4; Tr. 8, at 976).

28 Because of the difficulties associated with apportioning fungible assets of this nature, the Department has concluded that it is not appropriate or feasible to segregate capital structures between the gas and electric operations of combination gas and electric utilities. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 225 (2002); Fitchburg Gas and Electric Light Company, D.P.U. 1214-D at 4-5 (1985). These same difficulties are even more present when dealing with hypothetical corporate entities such as the former Colonial Gas.

accounts. Therefore, the Department allows the Company's request to consolidate its financial records for Boston Gas and the former Colonial Gas. In doing so, however, we direct National Grid to retain separate rate-base allocators under its coordinated GSEP in recognition of the separate replacement schemes and individual GSEP factors applicable to Boston Gas and the former Colonial Gas (Exh. NG-PP-1, at 64). D.P.U. 20-GSEP-03, at 1 n.1. The Department will consider the consolidation of service quality reporting metrics in the context of the Companies' service quality filings.

Accordingly, in conclusion, while the Department will allow the Company to file a unitary annual return and maintain its financial records on a consolidated basis, we direct the Company to continue to maintain separate GSEP and service quality data for Boston Gas and the former Colonial Gas, until otherwise directed.

IV. PERFORMANCE-BASED RATEMAKING PROPOSAL

A. Introduction

National Grid's proposed PBR plan includes four components: (1) a roll-in of post-test-year capital additions to occur with the first annual PBR adjustment; (2) a PBR mechanism designed to adjust rates annually and provide revenue support for operations and capital investment; (3) a proposal to extend the PBR for an additional five-year term; and (4) a set of performance incentive mechanisms ("PIMs") to motivate progress toward policy goals and scorecard metrics to monitor the Company's progress during the proposed five-year

PBR plan term (Exh. NG-PBRP-1, at 11-12 (Rev.)).[29] The Company foresees a number of changes to the operating environment for local distribution companies ("LDCs"), each requiring increased operating expense and capital requirements (Exh. NG-PBRP-1, at 8-9 (Rev.)). The Company states that the proposed PBR plan is the best regulatory structure to address these challenges and to provide customer benefits (Exh. NG-PBRP-1, at 8-9 (Rev.)).

B. Company Proposal

1. Introduction

National Grid's proposed PBR mechanism uses a revenue cap formula to adjust base distribution rates annually through an adjustment to the Company's revenue decoupling mechanism (Exh. NG-PBRP-1, at 19 (Rev.)). The PBR mechanism would adjust the base revenue requirement approved in this proceeding, which serves as the revenue target for the revenue decoupling mechanism, according to the following formula:

PBR percent $= (\text{GDP-PI}_{T-1} - X - CD) + (\text{ZREV}_T / \text{BASE\_REV}_{T-1})$, where

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

GDP-PI is a price inflation index;[30]

---

[29] The Company's initial PBR proposal also included a cost recovery component for the four demonstration programs that were part of the Company's initial filing; the Department has removed these demonstration programs from investigation in this proceeding. D.P.U. 20-120, Interlocutory Order on Four Demonstration Programs (December 11, 2020).

[30] The GDP-PI refers to the gross domestic product price index, which measures changes in the prices of goods and services produced in the United States, including those exported to other countries.

X is a productivity offset;

CD is a consumer dividend;

ZREV is an adjustment for exogenous costs (positive or negative);[31]

BASE_REV is the base distribution revenue requirement;

T indicates the Rate Year.

(Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 6.0).

An additional element in the Company's proposed PBR mechanism not shown in the above formula is the Company's proposed earnings sharing mechanism ("ESM"). The proposed ESM would provide either a credit or an additional charge to customers if earnings are higher than the return on equity ("ROE") approved in this proceeding by more than 100 basis points, or lower than the ROE approved in this proceeding by more than 150 basis points (Exhs. NG-PBRP-1, at 26 (Rev.); NG-PP-10, proposed M.D.P.U. No. 56, § 11.0). The Company proposes for ESM adjustments to be recovered through the Local Distribution Adjustment Factor ("LDAF") (Exh. NG-PBRP-1, at 20 (Rev.)). In addition, any incentives resulting from achieving targets for the proposed PIMs would be calculated separately and

---

https://www.bea.gov/data/prices-inflation/gdp-price-index. The GDP-PI is published by the Bureau of Economic Analysis ("BEA"), which is an independent principal financial statistical agency within the U.S. Department of Commerce.

31 The Company proposed that qualifying exogenous costs may be recovered through a separate factor if they are non-recurring in nature (Exh. NG-PBRP-1, at 20, 25 (Rev.)).

recovered through the LDAF (Exh. NG-PBRP-1, at 20 (Rev.)).[32] Each element of the Company's proposed revenue cap formula and PBR mechanism is described in detail below.

2. Formula Elements

a. GDP-PI

The Company proposed using the Gross Domestic Product-Price Index ("GDP-PI") as an inflation index in the PBR mechanism (Exh. NG-PBRP-1, at 21 (Rev.)). For each annual adjustment of the PBR mechanism, the Company proposed to calculate inflation as the percentage change between the current year's GDP-PI and the prior year's GDP-PI, with each year's GDP-PI calculated as the most recent four quarterly measures of GDP-PI as of the first quarter of the year, in order to align with the Company's annual PBR filing schedule (Exh. NG-PBRP-1, at 21 (Rev.)).

b. X Factor

National Grid proposed a productivity offset ("X factor") to be calculated as:

$X = [(\%\Delta TFP^{R}_{I} - \%\Delta TFP_{E}) + (\%\Delta W_{E} - \%\Delta W_{I})]$, where

---

32 The Company noted that amounts recovered through the LDAF would take effect on November 1 (the effective date of all LDAF changes), would be recovered over a 12-month period, and would not be included in the permanent adjustment to base distribution rates and RDM (Exh. NG-PBRP-1, at 20 (Rev.)). The Company notes that, in at least one prior case, the Department has approved an ESM adjustment to base distribution revenue (RR-DPU-36 & Att.). However, the Department understands from the Company's testimony, proposed tariff, and other evidence in the case that the Company's proposal is for a 12-month recovery of any ESM revenue through the LDAF (Exhs. NG-PBRP-1, at 20, 27; NG-PP-10, proposed M.D.P.U. No. 56, § 11.0; Tr. 7, at 855-856).

($\%\Delta TFP^{R}_{I} - \%\Delta TFP_{E}$) is the total productivity trend differential between the gas distribution industry in the Northeast region and the overall United States economy, and

($\%\Delta W_{E} - \%\Delta W_{I}$) is the total input price trend differential between the gas distribution industry and the overall United States economy.

(Exh. NG-MEM/NAC-1, at 16).

When a PBR mechanism utilizes an inflation factor that is a measure of economy-wide inflation, the X factor consists of the differential in expected productivity growth between the LDC industry and the overall economy, and the differential in expected input price growth between the overall economy and the LDC industry (Exh. NG-MEM/NAC-1, at 13). To determine the proposed X factor, National Grid conducted a productivity study of nationwide LDCs' distribution total factor productivity ("TFP") and input price growth over the period of 2004 through 2018 (Exh. NG-MEM/NAC-1, at 19-21). The Company used two different samples for this productivity study: (1) a sample of 85 U.S. LDCs intended to represent the overall nationwide LDC industry; and (2) a sample of 29 LDCs intended to represent the LDC industry in the Northeast (Exh. NG-MEM/NAC-1, at 21, App. A at 16-17). For the industry TFP study and calculation of the X factor, the Company used several official U.S. government sources.[33]

---

33 The Company used firm-level data for sample LDCs from Federal Energy Regulatory Commission Form 2 and the U.S. Energy Information Administration Form 176 (Exh. NG-MEM/NAC-1, App. A at 16). The Company used economy-wide data from: (1) BEA Price Index for GDP-PI; (2) U.S. Bureau of Labor Statistics ("BLS") Multifactor Productivity; (3) BLS Employer Cost Index; (4) Federal Reserve Bank of St. Louis, Corporate Bond Yields; (5) BLS Consumer Price Index; and (6) BLS

TFP is defined as the ratio of total output to total input (Exh. NG-MEM/NAC-1, at 13). TFP is considered a comprehensive measure of productivity because it includes the contribution of all inputs used in production of total output (Exh. NG-MEM/NAC-1, at 14). For the input measure, National Grid used labor, materials, and capital costs (Exh. NG-MEM/NAC-1, App. A at 4-12).[34] The Company constructed quantity and price indices of total input for each firm and each year (Exh. NG-MEM/NAC-1, at 13-14). National Grid used number of customers as the measure of TFP output (Exh. NG-MEM/NAC-1, at 14-15, App. A at 4).

In determining the input quantity of capital for the TFP study, the Company utilized a capital cost specification method referred to as the one hoss shay method (Exh. NG-MEM/NAC-1, App. A at 9). The basic assumption of this method is that an asset provides a constant level of services over the service life of the asset (Exh. NG-MEM/NAC-1, App. A at 9). The one hoss shay method also requires an average service life of all assets in order to estimate the quantity of capital retirements, which the

Producer Price Index for Construction (Exhs. NG-MEM/NAC-1, App. A; NG-MEM/NAC-5; NG-MEM/NAC-6).

34 Quantities of labor and materials were estimated using operations and maintenance costs across the gas distribution industry in conjunction with price data from U.S. government data sources (Exh. NG-MEM/NAC-1, App. A at 4-8). The input quantity of capital was derived using a perpetual inventory equation and a benchmark year of 1998, and capital prices were derived using an implicit rental price equation (Exh. NG-MEM/NAC-1, App. A at 8-12).

Company estimated to be 51 years (Exhs. NG-MEM/NAC-1, App. A at 9-10; NG-MEM/NAC-7).

The results of the Company's study indicated that, for the period 2004-2018, the average growth in productivity for the national LDC industry sample was equal to -0.05 percent, while the economy-wide productivity growth was equal to 0.53 percent, which generated a productivity differential of -0.59 percent for the study period (-0.05 percent less 0.53 percent = -0.59 percent) (Exh. NG-MEM/NAC-1, at 29).[35] For the same period, the average input price growth for the national LDC industry sample was equal to 2.37 percent, while the economy-wide input price growth was equal to 2.42 percent, which generated an input price differential of 0.05 percent (2.42 percent less 2.37 percent = 0.05 percent) (Exh. NG-MEM/NAC-1, at 29). The sum of the national productivity differential and the national input price differential in the Company's results generated an X factor of -0.54 percent (-0.59 percent plus 0.05 percent) (Exh. NG-MEM/NAC-1, at 29).

When the Company conducted the TFP study using its Northeast regional LDC industry sample, the average growth in productivity was -0.71 percent, which generated a productivity differential of -1.24 percent (Exh. NG-MEM/NAC-1, at 30). The Northeast regional sample also produced an industry input price growth average of 2.37 percent, which generated an input price differential of 0.04 percent (Exh. NG-MEM/NAC-1, at 30). The sum of the Northeast regional productivity differential and the Northeast regional input price

[35] Due to rounding, the numbers presented in the calculations of differentials may not add precisely to the totals.

differential in the Company's study generated an X factor of -1.19 percent (Exh. NG-MEM/NAC-1, at 30).

The Company proposed that the X factor corresponding to the Northeast regional sample be incorporated into the PBR mechanism due to differences in growth in the output and input components of TFP between the national sample and the Northeast regional sample (Exh. NG-MEM/NAC-1, at 32). The Company also cited differences in infrastructure and population density in the Northeast, which impact operating costs, as a reason to use the Northeast regional X factor (Exh. NG-MEM/NAC-1, at 33-36). During the proceeding, however, the Company determined that transmission plant had been misclassified in the initial calculation of TFP (Exh. DPU 8-8, at 2). The Company stated that correctly accounting for plant assets would decrease the Northeast regional X factor from -1.19 percent to -1.30 percent (Exhs. DPU 8-8, at 2; DPU 24-17, Att. 1).

c. <u>PBR Term</u>

National Grid proposed a five-year PBR term for the PBR plan (Exh. NG-PBRP-1, at 28 (Rev.)). The five-year PBR term would commence on October 1, 2021 and expire on September 30, 2026 (Exh. NG-PBRP-1, at 28 (Rev.)). Within the five-year term, there would be four annual PBR mechanism adjustments taking effect October 1, 2022, October 1, 2023, October 1, 2024, and October 1, 2025 (Exh. NG-PBRP-1, at 28 (Rev.)). In conjunction with the PBR term, National Grid proposed a stay-out provision whereby the Company may not file a base distribution rate case during the PBR term that would result in new base distribution rates going into effect earlier than October 1, 2026 (Exh. NG-PBRP-1, at 28 (Rev.)).

The Company conditioned a commitment to the proposed stay-out on two provisions: first, approval of the proposed PBR mechanism formula without material modification, and second, approval of the Company's proposal for recovery of incremental capital additions associated with its liquified natural gas ("LNG") facilities' "life-cycle" investments (Exh. NG-PBR-1, at 29-32 (Rev.)).[36] The Company also proposed a possible extension of the initial five-year term, at its own discretion, made possible by an adjustment to base distribution rates during the term extension (Exh. NG-PBRP-1, at 29 (Rev.)). In its June 15, 2025, PBR mechanism adjustment filing, National Grid would include a determination of whether it would opt to continue the PBR mechanism beyond the initial five-year term, ending September 30, 2026, with an adjustment to base distribution rates, or file a base distribution rate case or other proposal for effect October 1, 2026 (Exh. NG-PBRP-1, at 40 (Rev.)).

d. Post-Test-Year Capital Additions

National Grid included two proposals to incorporate post-test-year capital additions into base distribution rates as part of the PBR plan. First, the Company proposed to update cast-off rates as of the first annual PBR adjustment, effective October 1, 2022, to account for capital additions placed into service through December 31, 2021, exclusive of GSEP and

---

36 The proposed LNG life-cycle investments are discussed in Section X below.

LNG investments (Exh. NG-PBRP-1, at 36-38 (Rev.)).[37] The Company indicated that it would not be able to pursue the PBR plan without this proposed adjustment to cast-off rates (Exh. NG-PBRP-1, at 37 (Rev.)). Under this proposal, the Company estimates that $671 million in capital additions will be rolled into base distribution rates (Exh. DPU 5-7). Second, the Company provided an option for a five-year PBR term extension ("extended plan"), conditioned on updating base distribution rates to account for all capital additions placed into service on or after April 1, 2020, including: (1) GSEP capital additions placed into service on or after April 1, 2020; (2) non-GSEP, non-LNG capital additions placed into service on or after January 1, 2022; and (3) certain expense items related to NGSC IT programs (Exh. NG-PBRP-1, at 38-39 (Rev.)). National Grid proposed that the extended plan update to base distribution rates may occur in any year following the end of the initial five-year PBR plan term at the Company's discretion (Exh. NG-PBRP-1, at 40-41 (Rev.)). The amount of capital additions eligible to be rolled in under this proposal would depend on the timing of the update and would include all capital additions placed into service up to the end of the year prior to the request (i.e., December 31 of 2025, 2026, 2027, 2028, or 2029) (Exh. NG-PBRP-1, at 39 (Rev.)).

---

37 The Company proposed to include growth investments in the update to cast-off rates, and, as such, proposed for base distribution rates to be based on the updated revenue requirement, billing determinants, and number of customers as of December 31, 2021 (Exh. NG-PBRP-1, at 38 (Rev.)).

e. Consumer Dividend

National Grid proposed to include a consumer dividend of 0.15 percent in its PBR mechanism (Exh. NG-PBRP-1, at 23 (Rev.)). In theory, a consumer dividend reflects the productivity gains expected under PBR and returns a portion of those gains to customers (Exh. NG-LRK-1, at 6-7). The Company arrived at a consumer dividend of 0.15 percent based on the results of a cost benchmarking study that compared the Company's level of unit costs and TFP to other Northeast gas utilities (Exh. NG-PBRP-1, at 23 (Rev.)).[38]

f. Exogenous Cost Factor (Z Factor)

The Company proposed to include an exogenous cost provision ("Z factor"), which it defined as changes to its operating costs that arise from factors beyond National Grid's control (Exh. NG-PBRP-1, at 24 (Rev.)). Costs eligible for recovery through the Z factor would be those due to changes in tax laws, accounting requirements, or regulatory, judicial, or legislative changes, which uniquely affect the natural gas distribution industry (Exh. NG-PBRP-1, at 24 (Rev.)). The Company further proposed a two-part exogenous cost

[38] As discussed below, the Attorney General provides an alternative benchmarking analysis that addresses alleged deficiencies associated with the Company's study methods (Exh. AG-DED-1, at 45-55). The Attorney General's alternative benchmarking study analyzes operating expense performance, exclusive of capital costs, for a sample of 20 large utilities, defined as serving 200,000 customers or more, from four states in the Northeast (Exh. AG-DED-1, at 46). The Attorney General presents her alternative analysis over periods of five and ten years, and in terms of unit cost on a per-customer and per-Mcf basis, using throughput as a measure of volumetric demand (Exh. AG-DED-1, at 39, 43-47). Based on her review of the Company's benchmarking study and the results of her study, the Attorney General recommends a consumer dividend of 0.30 percent (Exh. AG-DED-1, at 55).

mechanism: the first part includes events that meet the Department's established criteria for an exogenous event (described above); and the second part defines a more targeted definition specific to exogenous events arising due to pipeline safety requirements imposed after November 13, 2020, with demonstrated cost impacts after the effective date of the PBR mechanism, October 1, 2021 (Exh. NG-PBRP-1, at 24 (Rev.)).

In addition, the exogenous cost for either proposed part would be required to meet a significance threshold of $2 million, which was determined by multiplying the Company's total operating revenues for calendar year 2019 of $1.571 billion by 0.001253[39] and then rounding upward (Exh. NG-PBRP-1, at 25 (Rev.)).[40] The Company proposed two slightly different treatments of the annual threshold for the two proposed parts of the definition of an exogenous cost: (1) the significance threshold for the first part, the traditional exogenous factor, would include operations and maintenance ("O&M") cost changes, and (2) the significance threshold for the second part, specific to pipeline safety requirements, would allow for both capital and O&M cost changes, applied separately to capital investments and O&M (Exh. NG-PBRP-1, at 24-25 (Rev.)). Further, the significance threshold for each part would be subject to annual adjustments based on changes in GDP-PI (Exh. NG-PBRP-1,

---

39 The Department has previously approved a factor of 0.001253 for use in deriving the threshold for exogenous cost recovery. D.P.U. 19-120, at 93-94; D.P.U. 18-150, at 66-67; D.P.U. 17-05, at 397.

40 The Company further explained that when considering the threshold for the Company's second part of the definition, the impact of a change in capital costs would be determined as the revenue requirement impact of the cost change attributed to the exogenous event (Exh. DPU 54-4).

at 25 (Rev.)). The Company proposed that recurring exogenous costs would be added to base distribution rates and that non-recurring exogenous costs would be collected through a separate factor (Exh. NG-PBRP-1, at 25 (Rev.)).

g. Earnings Sharing Mechanism

As part of the PBR mechanism, the Company proposed to adopt an ESM with a deadband of 100 basis points above and 150 basis points below the ROE authorized by the Department (Exh. NG-PBRP-1, at 26 (Rev.)). The proposed ESM would trigger a sharing of earnings with customers on a 75 (customers)/25 (shareholders) basis when the actual ROE exceeds 100 basis points above the allowed ROE (Exh. NG-PBRP-1, at 26 (Rev.)).[41] If the actual ROE is below the allowed ROE, the shortfall would be shared on a 50/50 basis between customers and shareholders if the shortfall is between 150 and 200 basis points below the allowed ROE, and on a 75 (customers)/25 (shareholders) basis if a shortfall exceeds 200 basis points below the allowed ROE (Exh. NG-PBRP-1, at 26-27 (Rev.)). National Grid proposed that calendar year ending December 2022 would be the first year for which the Company would evaluate whether an ESM adjustment were appropriate, for effect November 1, 2023 (Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 11.0).

---

41 The Company proposed that the ROE be calculated using earnings available for common equity as reported in the Company's annual Earnings Reports to the Department less Department-approved incentives, service-quality penalties, amounts related to regulatory or court settlements or decisions, and amounts related to prior application of the ESM. This adjusted earnings amount is then divided by average common equity as approved by the Department in this proceeding to produce the actual ROE for purposes of the ESM (Exh. NG-PBRP-1, at 27 (Rev.)).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General argues that the Department should reject the proposed PBR plan because it does not benefit ratepayers and is flawed (Attorney General Brief at 7, 12; Attorney General Reply Brief at 10). First, however, the Attorney General avers that the Department should defer consideration of any PBR plan until the Department completes its investigation in Role of Gas Distribution Companies as the Commonwealth Achieves Its Target 2050 Climate Goals, D.P.U. 20-80 (Attorney General Brief at 9).[42] The Attorney General argues that the Department's decision in that docket will influence the services provided by LDCs and the assets that are used to provide those services, and, therefore, will impact all proposed, planned investments (Attorney General Brief at 8). The Attorney General claims that it would be unjust and unreasonable for the Department to approve a rate plan of five or more years if the rate plan likely would need to change before the term ends (Attorney General Brief at 7; Attorney General Reply Brief at 7).

42 The Department has initiated a process for exploring strategies to enable the Commonwealth to achieve its 2050 climate goals. D.P.U. 20-80, Vote and Order Opening Investigation at 1 (October 29, 2020). Specifically, the Department will explore strategies to enable the Commonwealth to move into its net zero greenhouse gas emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth. D.P.U. 20-80, Vote and Open Opening Investigation at 1.

The Attorney General maintains that PBR plans in Massachusetts, such as the one proposed by the Company, have not demonstrated a benefit to ratepayers in the form of lower rates, but, instead, have resulted in rate increases following the plan terms (Attorney General Brief at 12-14; Attorney General Reply Brief at 5-6). Relatedly, the Attorney General argues that the PBR plan shifts any financial risk of committing to a PBR onto ratepayers, including through the inflation factor, the exogenous cost factor, the ESM, among other design components (Attorney General Reply Brief at 9-10).

While the Attorney General makes the above arguments as to why the proposed PBR plan should be rejected, she also recommends modifications, summarized below, should the Department approve a PBR plan for National Grid (Attorney General Brief at 12).

b. PBR Term

The Attorney General argues that the Department has previously found that five-year terms are not long enough to achieve the efficiencies and benefits that a PBR plan is expected to provide (Attorney General Brief at 14). The Attorney General claims that the Company has not provided new evidence to support the request for a five-year term (Attorney General Reply Brief at 14). Further, the Attorney General argues that the potential changes to the industry that are under consideration in D.P.U. 20-80 may be incompatible with a five-year PBR plan (Attorney General Reply Brief at 7). Finally, the Attorney General alleges that National Grid’s proposed tariff contains no provision prohibiting the Company from filing for a base distribution rate increase during the PBR term, which shifts risks of committing to a PBR away from the Company and onto ratepayers (Attorney General Reply Brief at 9-10).

c. Cost Recovery Mechanisms

The Attorney General claims that, even under the proposed PBR, a significant portion of the Company's costs will be recovered through new and existing cost recovery mechanisms, which the Attorney General claims constitutes cost of service ratemaking (Attorney General Brief at 15-16). Further, the Attorney General alleges that, because the data used to calculate the X factor includes all capital additions, a PBR formula increase in addition to the Company's GSEP capital tracker,[43] and the proposed LNG and IT expense cost recovery mechanisms, will provide double recovery (Attorney General Brief at 17, citing Tr. 5, at 595-596; Attorney General Reply Brief at 7-9 n.9). Similarly, the Attorney General argues that, if a PBR plan is allowed, the Department should disallow the roll-in of investments that are recovered through capital trackers, including the GSEP charge, the GBE charge, and the proposed LNG and IT charges (Attorney General Brief at 19). The Attorney General notes that 100 percent of these costs already are recovered through the capital trackers (Attorney General Brief at 19). Thus, she contends that allowing these costs to be incorporated into base distribution rates will provide over-recovery of the costs because the costs will be improperly inflated (Attorney General Brief at 19). Finally, if the PBR plan is approved, the Attorney General recommends that the Department reject the Company's

[43] Capital tracker is the generic term for a ratemaking mechanism that allows annual adjustments for annual recovery of costs associated with eligible infrastructure investments.

proposed LNG and IT expense cost recovery mechanisms (Attorney General Brief at 18; Attorney General Reply Brief at 9).

d. Post-Test-Year Capital Additions

The Attorney General provides recommendations to modify the Company's proposed capital addition roll-ins, should the Department allow them (Attorney General Brief at 18-19). These recommendations include requiring the Company to synchronize capital investments rolled into base distribution rates with the revenues and billing determinants to the same point in time, and excluding investments made after September 30, 2021 (Attorney General Brief at 18-19).

e. X Factor

The Attorney General argues that the X factor is "misspecified" due to the inclusion of costs that are otherwise recovered through reconciling mechanisms, including GSEP-related capital, LNG production and storage plant, software, pension/PBOPs, among others, which she claims may impact the magnitude of the X factor (Attorney General Brief at 19-20). Therefore, the Attorney General asserts that, because the magnitude of the X factor reflects activities for which the Company is already recovering cost increases, the proposed PBR formula should be rejected (Attorney General Brief at 20).

f. Consumer Dividend

i. Introduction

The Attorney General raises several concerns regarding the Company's proposed consumer dividend and the underlying benchmarking study (Attorney General Brief at 21-22).

First, the Attorney General indicates that the Department should not approve a consumer dividend that is equal to what was approved for NSTAR Gas Company ("NSTAR Gas") in D.P.U. 19-120, as the Company proposes, because the Company's cost efficiency performance is worse than that of NSTAR Gas (Attorney General Brief at 22-23; Attorney General Reply Brief at 12-14).

Second, the Attorney General argues that the benchmarking study conducted by the Company is flawed based on (1) the choice of peer group, (2) the time period of analysis, and (3) the use of number of customers as the measure of output (Attorney General Brief at 21-27). The Attorney General maintains that her alternative benchmarking analysis (see n.38 above) is sound, and the Department should disregard the Company's arguments against it (Attorney General Brief at 22, 28; Attorney General Reply Brief at 11-12).

ii. Cost Efficiency Compared to NSTAR Gas

The Attorney General argues that the Department should not approve a consumer dividend that is equal to what was approved for NSTAR Gas in D.P.U. 19-120, as National Grid proposes, because the Company's cost efficiency performance, demonstrated by both its own benchmarking study and the Attorney General's alternative analysis, is worse than that of NSTAR Gas (Attorney General Brief at 22-23; Attorney General Reply Brief at 13). Instead, the Attorney General argues that the Department should approve a higher consumer dividend relative to NSTAR Gas (Attorney General Reply Brief at 14). Specifically, the Attorney General notes that National Grid's benchmarking results indicate that the Company's unit cost is 42.2 percent higher than that of NSTAR Gas (Attorney General Brief at 22, citing RR-AG-13; Attorney General Reply Brief at 13). Further, the Attorney General notes that her benchmarking analysis provides a similar finding, that the Company's transmission and distribution O&M costs were three times that of NSTAR Gas on a per-thousand cubic foot ("Mcf") basis and 150 percent greater than NSTAR Gas on a per-customer basis (Attorney General Brief at 23, citing Exh. AG-DED-1, at 48; Attorney General Reply Brief at 13).

iii. Choice of Peer Group

The Attorney General takes issue with the Company's comparison of its cost efficiency to a peer group of four other LDCs servicing urban centers in the U.S. (Attorney General Brief at 24). Specifically, the Attorney General argues that this peer group comparison is limited in that it only spans three geographic areas, only includes three non-affiliates of the Company, and that the Department has historically not placed weight on similar peer group comparisons, and, instead, the Department has found appropriate a larger national peer group comparison (Attorney General Brief at 24-25, citing Exhs. NG-MEM/NAC-1, at 21; NG-LRK-2, at 5; D.P.U. 18-150, at 63-64).

In addition, the Attorney General claims that National Grid failed to substantiate a related critique that the Attorney General's alternative peer group is flawed because it does not account for the purported higher level of pipeline replacement the Company faces (Attorney General Brief at 25, 29). The Attorney General points out that replacing aged infrastructure has been a cost challenge for most utilities in the Northeast and Mid-Atlantic regions, as well as in non-urban areas (Attorney General Brief at 29; Attorney General Reply

Brief at 14). The Attorney General contends that National Grid's analysis of pipeline replacement data is deficient in that it aggregates the Company with other urban peers and does not normalize pipeline replacement with system size (Attorney General Reply Brief at 15, citing RR-AG-15). The Attorney General presents an analysis of the same data, which she claims indicates that non-urban LDCs have seen their inventory of unprotected steel and cast-iron mains decrease by more than half and more than a third, respectively, relative to 2004 levels (Attorney General Brief, at 29-30, citing RR-AG-15; Attorney General Reply Brief at 15-16).

iv. Time Period of Analysis

The Attorney General indicates that the Company's use of a three-year time period (2016-2018) in its benchmarking analysis to support the proposed PBR plan is limited and inconsistent with other parts of the analysis (Attorney General Brief at 26). Specifically, the Attorney General notes that the Company seeks approval for a five-year PBR term but uses a period of three years for the benchmarking cost comparison, a period of ten years for a comparison of mains replacement, and a period of 15 years in the TFP analysis (Attorney General Brief at 26). The Attorney General asserts that her benchmarking analysis presents results for a period of five years and a period of ten years, and she asserts that the Company's cost performance deteriorates over time, and conversely, that NSTAR Gas' performance improves over this time (Attorney General Brief at 26, 29).

v. Measure of Output

The Attorney General claims that the Company's exclusive reliance on number of customers as a measure of output does not reflect the cost causation considerations that are used in a typical "Class Cost of Service Study," which would instead classify distribution costs as demand-driven (Attorney General Brief at 27). The Attorney General points out that National Grid acknowledges that peak demand is an important cost driver, but the Company omits peak demand from its benchmarking analysis because the Company claims that data on peak demand is not readily available (Attorney General Brief at 27-28, citing Tr. 5, at 570-571; Attorney General Reply Brief at 12). The Attorney General notes that her alternative benchmarking study uses annual throughput as a measure of demand (Attorney General Brief at 27; Attorney General Reply Brief at 12). The Attorney General maintains that this metric is related to peak demand, despite the Company's argument that this metric is insufficient to represent a cost driver (Attorney General Brief at 27; Attorney General Reply Brief at 12). Further, the Attorney General rejects any notion that the use of delivery volume as an output metric undermines demand resource and energy efficiency goals (Attorney General Reply Brief at 12, citing Company Brief at 61 n.24). Instead, she asserts that the same would hold true if a measure of peak demand were used as an output metric, which the Company purportedly supports, and such a notion assumes that costs are fixed, which they are not if a utility is able to identify cost savings (Attorney General Reply Brief at 12).

vi. Capital Costs

The Attorney General maintains that the Department should disregard any critique that her alternative benchmarking analysis improperly excludes capital costs, and she asserts that capital costs should not be considered because major capital expenses are recovered outside of the PBR (Attorney General Brief at 28-29).

g. Exogenous Cost Factor

The Attorney General contends that the exogenous cost factor would be a suitable vehicle for passing back to customers any overcharges related to criminal activity on the part of affiliate company employees that are embedded in current rates and the proposed cost of service in this case, provided the significance threshold is eliminated in the context of such overcharges (Attorney General Supplemental Brief at 8, 11-12). As discussed in greater detail in Section XI.D. below, the Department will consider in a separate proceeding, proposals for the appropriate ratemaking treatment for any such overcharges.

2. TEC

TEC argues that the Company's proposed consumer dividend factor of 0.15 percent is too low (TEC Brief at 10). TEC contends that a consumer dividend of 0.15 percent conflicts with Department precedent and fails to offer a sufficient incentive to the Company for productivity improvements (TEC Brief at 10). Accordingly, TEC asserts that the Department should adopt a consumer dividend of 0.30 percent (TEC Brief at 10-11, citing Exh. AG-DED-1, at 55).

3. Company

a. Introduction

National Grid contends that the PBR plan provides the best regulatory structure to allow the Company to address a challenging and uncertain operating environment for LDCs, while also providing benefits to ratepayers by addressing these challenges using innovative means and by controlling costs (Company Brief at 8-9; Company Reply Brief at 2). The Company identifies several primary factors impacting its future operations that are expected to drive increases in operating expenses and capital investment (Company Brief at 8-9; Company Reply Brief at 3). Specifically, the Company identifies the need to focus on core safety and reliability responsibilities, particularly in light of the Merrimack Valley incident,[44] in addition to requirements to reduce greenhouse gas ("GHG") emissions (Company Brief at 8-9; Company Reply Brief at 2-3).[45] Further, the Company maintains that, given its projected financials and required upcoming infrastructure investments, its base distribution

---

[44] On September 13, 2018, the former Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, experienced an over-pressurization of its low-pressure distribution system serving the City of Lawrence and the towns of Andover and North Andover in the Merrimack Valley. National Transportation Safety Board Pipeline Accident Report, NTSB/PAR-19/02 (NTIS No. PB2019-101365), adopted September 24, 2019 ("NTSB Report") at 1. The over-pressurization allowed natural gas from a high-pressure distribution system to enter the low-pressure distribution system. NTSB Report at 1. This lack of proper system regulation resulted in the damage or destruction of 131 homes and businesses, the hospitalization of 22 individuals, and the death of one person. NTSB Report at 1.

[45] Methane (CH_4) is a GHG and it is the primary component of natural gas. https://www.gov/ghgemissions/overview-greenhousefases#metnane.

rate cases would become more frequent (Company Brief at 10). National Grid asserts that the PBR framework provides the revenue support to avoid additional base distribution rate cases and incentivizes cost reductions and increased operational efficiencies (Company Brief at 10; Company Reply Brief at 3).

b. Benefits of a PBR Plan

National Grid argues that its proposed PBR plan will provide both increased economic benefits and customer experience benefits as compared to cost of service ratemaking (Company Brief at 10-13). The proposed PBR plan, the Company contends, can provide a monetized benefit of up to $2.5 million for each avoided base distribution rate case and allow its staff to redirect time and focus from rate case proceedings to the Company's current challenges (Company Brief at 52, citing Exhs. DPU 5-2; DPU 54-3 (Supp.)). The Company claims that the economic benefits of a PBR plan also include a greater incentive to achieve efficiency, better service, and reduced unit costs, and that those benefits would be reflected in lower future rates than without a PBR plan (Company Brief at 11). National Grid further claims that the PBR plan will position the Company to improve internal operations and technology, which, in turn, will allow it to meet increasing customer expectations of their utility service (Company Brief at 12). Finally, the Company asserts that the PBR plan provides the financial support to allow Company management to redirect focus from regulatory matters to core operations, such as improving regulatory compliance and safety (Company Brief at 13).

The Company rejects claims made by the Attorney General that there is no evidence that a PBR plan provides benefits to customers (Company Brief at 51-52; Company Reply Brief at 4). The Company maintains that the Attorney General's assertion, which she supports with citations to previous PBR plans approved by the Department that did not complete their full PBR terms, ignores the challenging operating environment LDCs currently face (Company Brief at 52; Company Reply Brief at 4-5). National Grid asserts that the prior PBR plans did not address cost pressures faced by those companies, and that the Attorney General does not consider the protections that the Company's proposed PBR plan has in place to allow it to avoid the pitfalls of prior PBR plans and to meet the stay-out commitment, including appropriate support for capital investment (Company Brief at 52-53; Company Reply Brief at 7-8). Further, National Grid argues that the prior PBR plans functioned for the five-year terms proposed, not the longer terms approved, and were successful in avoiding base distribution rate cases, as evidenced by the fact that Boston Gas filed for two rate cases during the 14-year term that it was under a PBR plan (Company Reply Brief at 4-6). National Grid also claims that it provided viable evidence that a previous PBR plan for Boston Gas led to efficiency gains (Company Brief at 55-56, citing Exh. NG-LRK-1, at 12-14; Company Reply Brief at 4). Finally, National Grid argues that the Attorney General is mistaken in her assertion that a rate increase following a PBR demonstrates a lack of customer benefits, as the Company asserts that a PBR plan is not intended to eliminate the need for rate increases altogether, but, instead, is intended to result in lower rates than would be expected under cost of service ratemaking (Company Brief at 53; Company Reply Brief at 7).

c. PBR Term

National Grid argues that the proposed five-year PBR term with an option for extension can reduce regulatory burden and associated customer costs; without a PBR plan, the Company anticipates needing to file a base distribution rate proceeding within three years (Company Brief at 29, citing Exh. NG-PBRP-1, at 29 (Rev.)). The Company insists that the PBR plan would avoid at least one base distribution rate case during the five-year term (Company Brief at 29). Further, the Company maintains that there are several factors rendering it infeasible to commit to a stay-out period of more than five years, including planned IT investments that alone could necessitate filing a base distribution rate case (Company Brief at 29 n.14, citing Exh. NG-PBRP-1, at 33-34 (Rev.); Company Reply Brief at 13-14).

National Grid argues against the Attorney General's claim that the Company has not provided new evidence to support the request for a five-year term. Rather, the Company claims that it has provided data, analysis, and other supporting evidence to demonstrate that a five-year term is sufficient to generate strong incentives for cost savings, achieve regulatory results, and create an appropriate balance between providing performance incentives and mitigating business and policy risks (Company Brief at 54-55, citing Exh. NG-LRK-1, at 10-12; Company Reply Brief at 10-11). The Company also states that its own PBR experience provides evidence that a five-year plan is sufficient to generate efficiencies and create cost savings, and further contends that there is no evidence that a five-year plan would fail to generate strong incentives (Company Brief at 55-56, citing Exh. NG-LRK-1, at 12-14; Company Reply Brief at 12).

Finally, National Grid argues that PBR terms longer than five years are not typical, can cause misalignment between the plan and operating circumstances, and have resulted in an inability to sustain such plans (Company Brief at 57-58, citing Exhs. DPU 8-11, at 2; NG-LRK-1, at 11, 12-13; Company Reply Brief at 11, 14, citing DPU 8-11, at 5; Company Reply Brief at 12, citing Exh. NG-LRK-1, at 12). In particular, the Company notes that the potential outcome of D.P.U. 20-80 could be incompatible with a ten-year PBR plan term (Company Reply Brief at 13, citing Exh. NG-LRK-1, at 14-20).

d. Cost Recovery Mechanisms

National Grid rejects the Attorney General's argument that allowing capital trackers alongside the PBR plan converts the plan into a cost of service ratemaking framework (Company Brief at 58; Company Reply Brief at 16). The Company argues that the Attorney General misrepresents how a PBR plan functions and what the TFP study is intended to analyze (Company Brief at 58; Company Reply Brief at 16). The Company explains that the TFP study analyzes the relationship between total output and total input, one category of which is capital investment; however, the recovery mechanism for capital has no bearing on the relationship TFP seeks to measure (Company Brief at 58, citing RR-AG-16). The Company concludes that this distinction means that there is no risk of double-recovery (Company Brief at 58; Company Reply Brief at 16). Further, the Company contends that the

PBR mechanism adjusts revenues in accordance with a formula and is not intended to recover costs (Company Brief at 59). Instead, the Company argues, the PBR plan will only provide sufficient revenue support if the capital trackers are in place with the PBR plan (Company Brief at 59-60). Finally, the Company indicates that the ESM will protect against over-earning under the PBR plan (Company Brief at 61).

The Company also maintains that it cannot commit to the PBR stay-out without approval of the proposal to recover incremental capital additions associated with its LNG facilities (Company Brief at 30, citing Exhs. NG-PBRP-1, at 30 (Rev.); DPU 54-5). The Company argues that the cost of upgrades during the five-year PBR term is significant, and that the design of the annual PBR adjustment does not account for this type of non-routine investment (Company Brief at 30, citing Exhs. NG-PBRP-1, at 30 (Rev.); DPU 54-5).

e. Post-Test-Year Capital Additions

National Grid maintains that it cannot pursue a PBR plan unless capital additions through December 31, 2021, exclusive of GSEP and LNG, are included in base distribution rates during the initial five-year plan term (Company Brief at 32). The Company argues that, to make the proposed PBR Plan practicable, rates must align with the Company's current costs to provide adequate financial support during the PBR term (Company Brief at 31, citing Exh. NG-PBRP-1, at 36 (Rev.)). National Grid notes that, to support the inclusion of capital additions, it will file the necessary project documentation with the Department with the first annual PBR rate adjustment filing on June 15, 2022, for inclusion in rates as of October 1, 2022 (Company Brief at 32, citing Exh. NG-PBRP-1, at 37 (Rev.)).

In addition, the Company will include in the filing a proposal to adjust base distribution rates and base revenue per customer based on the updated revenue requirement, updated billing determinants, and updated number of customers as of December 31, 2022 (Company Brief at 32, citing Exh. NG-PBRP-1, at 38 (Rev.)).

The Company indicates that, in order to extend the PBR term to ten years, it also would require a one-time update to distribution rates through a rate base adjustment for effect October 1, 2026, or later (Company Brief at 33). Accordingly, National Grid maintains that, should it elect to extend the PBR term, it would notify the Department of its intention to do so in the final PBR filing in the initial five-year term (Company Brief at 33, citing Exh. NG-PBRP-1, at 40 (Rev.)).

f. X Factor

The Company proposes an X factor of -1.30 percent based on a TFP study of productivity trends in the gas distribution industry in the Northeast (Company Brief at 15). The Company explains that a negative X factor does not mean that the industry's productivity growth is declining (Company Brief at 16). Further, the Company notes that a negative X factor can result if changes in productivity and input prices for the industry are less favorable than changes in productivity and input prices in the overall economy, which can occur for the LDC industry due to factors such as reliance on local, unionized labor and other inputs that are not able to take advantage of global sourcing or other technologically-driven productivity gains that benefit other industries (Company Brief at 16).

The Company avers that it is not necessary or appropriate to adjust the X factor to account for the GSEP mechanism (Company Brief at 20, citing Exh. NG-MEM/NAC-1, at 36). First, the X factor is calculated to measure changes in physical productivity and not how costs are recovered (Company Brief at 20, citing Exh. NG-MEM/NAC-1, at 36; Tr. 5, at 599-600). Second, real capital additions funded through the GSEP are likely to be matched by retirements, which results in no net change to capital input or, therefore, to TFP (Company Brief at 20, citing Exhs. NG-MEM/NAC-1, at 37; DPU 8-8). Third, it would not be feasible to calculate the impact of GSEP on the X factor due to data limitations (Company Brief at 20, citing Exhs. NG-MEM/NAC-1, at 37; DPU 8-8). Finally, the Company argues that a determination not to adjust the X factor to account for GSEP would be consistent with the Department's finding in D.P.U. 19-120 (Company Brief at 21). More generally, the Company argues that cost recovery mechanisms are not relevant for the calculation of TFP and, therefore, for the X factor (Company Brief at 58). For this reason, National Grid maintains that the Attorney General's argument that the X factor is flawed is without merit (Company Brief at 60).

Finally, the Company rebuts the Attorney General's claim that the proposed PBR plan shifts all risk away from National Grid's shareholders to customers (Company Reply Brief at 17). National Grid asserts that the input price component of the X factor can differ from the input price changes that the Company may actually experience under a PBR plan (Company Reply Brief at 17). Further, according to the Company, these risks are greater in a high-inflation than in a low-inflation environment, and there is evidence that economy-wide inflation is increasing (Company Reply Brief at 17). In addition, the Company contends that, contrary to the Attorney General's assertions, changes in the cost of capital will not be reflected in the Company's proposed X factor or inflation factor (Company Reply Brief at 17).

g. Consumer Dividend

i. Introduction

The Company argues that its proposed consumer dividend of 0.15 percent is supported by both a benchmarking study and by Department precedent, namely the Department's recent decision in D.P.U. 19-120 (Company Brief at 21; Company Reply Brief at 18-19). The Company maintains that the benchmarking analysis conducted in support of the consumer dividend provides empirical evidence that can be used to support the Department's judgment on an appropriate consumer dividend (Company Brief at 22).

ii. Cost Efficiency Compared to NSTAR Gas

National Grid contends that the results of its benchmarking analyses indicate that it experienced similar cost performance when compared to NSTAR Gas, and, therefore, the Company proposes a consumer dividend of 0.15 percent, equivalent to the consumer dividend approved for NSTAR Gas in D.P.U. 19-120 (Company Brief at 23-25; Company Reply Brief at 19-20). The Company explains that both utilities are in the upper quartile of cost performers in the national industry sample and top performers in the Northeast regional industry sample (Company Brief at 24, citing Exh. NG-LRK-1, at 55). Further, the Company argues that its analysis suggests that Boston Gas incurred more capital replacement expenditures compared to NSTAR Gas, which demonstrates that the two utilities are comparable cost performers (Company Brief at 24-25, citing Exh. NG-LRK-1, at 56-57). National Grid argues that the Attorney General's position that the Company is comparatively less efficient ignores the impact of such differences in business conditions that increase the cost of maintaining and replacing assets (Company Reply Brief at 19).

iii. Choice of Peer Group

National Grid maintains that its benchmarking analysis included three peer groups: (1) a national sample of 85 companies; (2) a Northeast sample of 29 companies; and (3) an urban peer group of four companies (Company Brief at 23-24 n.13; Company Reply Brief at 20). National Grid claims that the Attorney General's benchmarking analysis peer group does not account for certain cost conditions for which the Company's study seeks to correct (Company Brief at 66, citing Exh. NG-LRK-Rebuttal-1, at 21). The Company further contends that the Attorney General's analysis of pipeline replacement data does not support a conclusion that there is no difference between the challenges facing urban and non-urban LDCs (Company Brief at 67; Company Reply Brief at 20). In addition, the Company contends that it did provide relevant information showing that it appropriately normalizes for the size of the system when considering pipeline replacement trends, contrary to the Attorney General's assertion (Company Reply Brief at 22-23, citing RR-AG-15). National Grid maintains that Boston Gas was more active in replacing cast iron and bare steel assets than the peers included in the Attorney General's benchmarking sample, and, therefore, the Company and the Attorney General's peer group are not adequate cost comparators

(Company Brief at 66-68). National Grid concludes that the Department should consider that the nature of the Company's service territory should not be mistaken for inefficiencies when determining the Company's consumer dividend (Company Reply Brief at 23).

iv. Time Period of Analysis

The Company argues that using a three-year period of analysis for benchmarking reflects that the consumer dividend is forward-looking and appropriate for capturing current cost efficiency at the outset of a PBR plan and is consistent with Department precedent (Company Brief at 64, citing Exh. NG-LRK-Rebuttal-1, at 23). Further, the Company contends that the Attorney General's assertion that using a three-year period for benchmarking is problematic is based on a misunderstanding of prior studies (Company Brief at 63-64).

v. Measure of Output

The Company contends that the benchmarking results provided by the Attorney General that use gas throughput as an output metric should be disregarded (Company Brief at 63). According to the Company, peak demand and not total throughput is the relevant volume-related cost driver, particularly since using delivery volume undermines demand resource and energy efficiency goals (Company Brief at 63).

h. Exogenous Cost Factor

National Grid argues that the Z factor is a necessary component of the PBR plan because the Company would be committing to a five-year stay-out, during which revenues would need to be adjusted to address costs changes arising from events outside of the

Company's control (Company Brief at 25). National Grid contends that the two-part Z factor is necessary to address uncertainty in potential future pipeline safety requirements, and the possibility that such requirements arise outside of the regulatory, judicial, and legislative channels addressed in the traditional exogenous cost definition (Company Brief at 25-27). Further, the Company asserts that the use of a significance threshold to trigger eligibility for exogenous cost recovery, and the calculation used to arrive at the proposed $2 million significance threshold are consistent with Department precedent (Company Brief at 27, citing Exh. NG-PBRP-1, at 25 (Rev.); D.P.U. 17-05, at 397).

Finally, the Company rebuts the Attorney General's assertion that the proposed PBR plan shifts all risk away from shareholders and on to customers, by explaining that risk mitigation measures, such as the Z factor, only provide partial cost protection and only after a lag associated with the filing and adjudication of requests for exogenous cost recovery (Company Reply Brief at 18). For instance, National Grid notes that the Z factor is limited in the types of costs it can recover, and that the Company maintains exposure to costs below the threshold and must file for and await adjudication by the Department of cost recovery applications (Company Reply Brief at 18).

i. Earnings Sharing Mechanism

National Grid contends that the proposed, asymmetrical ESM, identical to the ESM approved by the Department for NSTAR Gas in D.P.U. 19-120, is designed to provide customers with rate relief if the PRB plan leads to the Company over-earning its allowed ROE, and to maintain financial strength should the Company not earn its allowed ROE

(Company Brief at 28-29). The Company rebuts the Attorney General's assertion that the proposed PBR plan shifts all risk away from shareholders and on to customers by explaining that the ESM provides only partial protection and is limited to shortfalls outside of the deadband, and the ESM filings are subject to a significant lag (Company Reply Brief at 18).

D. Analysis and Findings

1. Introduction

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

2. Department Ratemaking Authority

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

The Department is not compelled to use any particular method to establish rates, provided that the end result is not confiscatory (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment). Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 19 (1978). The Supreme Judicial Court has held that a basic principle of ratemaking is that "the department is free to select or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal." American Hoechest Corporation v. Department of Public Utilities, 379 Mass. 408, 413 (1980), citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 302 (1978).

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

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, there are many variations and adjustments in the specific application of this model to individual utilities as circumstances differed across companies and across time. D.P.U. 07-50, at 8. Over the years, electric and gas distribution companies subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See, e.g., D.P.U. 19-120, at 58; D.P.U. 18-150, at 47; D.P.U. 17-05, at 371-372; Bay State Gas Company, D.T.E. 05-27, at 382 (2005); D.T.E. 03-40, at 471; D.T.E. 01-56, at 10; Massachusetts Electric Company/Eastern Edison Company, D.T.E. 99-47, at 4-14 (2000).

Consistent with the discussion above, the Department reaffirms that we may implement PBR as an alternative to cost of service/rate of return regulation under the broad ratemaking authority granted to us by the Legislature under G.L. c. 164, § 94.[46] The Department reviews the Company's specific PBR proposal under the standards set forth below.

3. Evaluation Criteria for PBR

The Department must approach the setting of rates and charges in a manner that: (1) meets our statutory obligations under G.L. c. 164, § 94, to ensure rates that are just and reasonable, not unjustly discriminatory, or unduly preferential; and (2) is consistent with long-standing ratemaking principles, including fairness, equity, and continuity. D.P.U. 07-50, at 10-11. Further, the Department must establish rates in a manner that balances a number of these key principles to reflect and address the practical circumstances attendant to any individual company's base distribution rate case. D.P.U. 07-50-A at 28. The Department has implemented PBRs or PBR-like mechanisms on a finding that such regulatory methods would better satisfy our public policy goals and statutory obligations.

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

See, e.g., Boston Gas Company, D.P.U. 96-50 (Phase I) at 261 (1996); Incentive Regulation, D.P.U. 94-158, at 42-43 (1995); New England Telephone and Telegraph, D.P.U. 94-50, at 139 (1995).

As part of our investigation of incentive ratemaking, the Department examined the criteria to evaluate PBR proposals for electric and gas distribution companies. D.P.U. 94-158, at 52-66. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by G.L. c. 164, § 94, which requires that rates be just and reasonable. Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984); D.P.U. 94-158, at 52. Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 94-158, at 57. Finally, a well-designed incentive mechanism should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57.

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

4. Rationale for PBR

There is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts. This evolution has been driven, in large part, by two factors. First, the Commonwealth has instituted several legislative and administrative policy initiatives designed to address climate change and to foster a clean energy economy. An Act Relative To Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298; Green Communities Expansion Act, § 83A; Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016); An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("Climate Act").[47] Second, the Merrimack Valley incident has prompted

47 In particular, pursuant to the Climate Act, the Commonwealth set a 2050 statewide emissions limit that achieves at least net zero statewide greenhouse gas emissions; provided, however, that in no event shall the level of emissions in 2050 be higher than a level 85 percent below the 1990 level.

changes in statutory and regulatory requirements that increase the natural gas distribution industry's focus on safety and compliance, which, in turn, will impact the operations and management of companies in the industry in areas such as workforce requirements, programs and processes, and operational expenses (Exhs. NG-PBRP-1, at 8, 15-16 (Rev.); NG-MLR-1, at 24). An Act Further Providing for the Safety of the Commonwealth's Natural Gas Infrastructure, St. 2018, c. 269. To varying degrees, this evolution is changing the operating environment for LDCs in Massachusetts.

As described above, National Grid proposes to implement a PBR mechanism that would adjust rates annually in accordance with a revenue-per-customer formula (Exh. NG-PBRP-1, at 19-20 (Rev.)). National Grid claims that a PBR mechanism is a better fit than cost of service ratemaking for providing the Company with the revenue support that it needs to address these changing industry dynamics, as well as to maintain or improve customer satisfaction and meet the Department's goals of safety, reliability, and affordability (Exhs. NG-PBRP-1, at 12-13 (Rev.); NG-MLR-1, at 12, 25). Specifically, the cost control incentives, potential for innovation, and steady financial support inherent in the PBR plan will be beneficial in light of the Company's expected increase in financial and operational demands as it addresses changes in the industry operating environment (Exhs. NG-PBRP-1, at 12-13, 18 (Rev.); NG-MLR-1, at 12; DPU 54-1). Further, the Company states that the PBR plan is more administratively efficient and will reduce administrative burden compared to cost of service ratemaking (Exhs. NG-PBRP-1, at 9, 11-12, 15, 28 (Rev.); DPU 54-3 (Supp.)). For the reasons discussed below, the Department finds that National Grid has demonstrated that an alternative to traditional cost of service/rate of return ratemaking is warranted.

National Grid demonstrated that its system needs are changing and that its capital and operating costs are increasing in ways that it has not experienced in the past. The Company argues that there are three changes in the natural gas distribution industry that are redefining the operating landscape: (1) evolving safety requirements and best practices; (2) additional energy and climate policy; and (3) increasing customer expectations and engagement (Exhs. NG-PBRP-1, at 15 (Rev.); NG-MLR-1, at 12-13, 25). The Company expects for these industry-wide changes to require substantial capital investment and operating costs, as well as increased flexibility and management focus to design and implement the necessary investments, programs, and operations (Exhs. NG-PBRP-1, at 13, 15-18 (Rev.); NG-MLR-1, at 12-13, 22). National Grid expects for these cost pressures to impose significant financial burden on the Company and that the PBR plan will provide a means of maintaining financial integrity for the PBR term and provide a strong incentive to reduce costs and manage available resources efficiently (Exhs. NG-PBRP-1, at 13 (Rev.); DPU 54-1; DPU 54-7).

The Department has allowed companies to adopt various capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate cases. D.P.U. 15-155, at 40, 51-54; D.P.U. 15-80/D.P.U. 15-81, at 50; D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; Bay State Gas Company, D.P.U. 09-30, at 133-134 (2009). The Department finds that a PBR mechanism provides the Company more flexibility to address a changing operating environment (Exhs. NG-PBRP-1, at 13 (Rev.); NG-MLR-1, at 12-13; DPU 54-1). The approach we adopt addresses the need for increased operating costs and allows National Grid to best meet its public service obligations for providing safe, reliable, and least-cost service to customers in an equitable manner, as well as to contribute to meeting the Commonwealth's emission reduction and pipeline safety goals. D.P.U. 94-158, at 57; G.L. c. 25, § 1A.

As part of the PBR plan, the Company has committed to refraining from filing rate schedules that would result in new base distribution rates going into effect during the PBR term (Exh. NG-PBRP-1, at 28 (Rev.)). The Department accepts that this stay-out provision will generate diminished administrative burden and will result in future efficiencies (Exhs. NG-PBRP-1, at 9, 28 (Rev.); NG-MLR-1, at 13-14). D.P.U. 19-120, at 63; D.P.U. 17-05, at 402. For instance, National Grid estimates that, without the PBR mechanism, the Company would need to pursue a base distribution rate case every two to three years (Exhs. NG-PBRP-1, at 9 (Rev.); NG-MLR-1, at 14; NG-LRK-1, at 11; DPU 5-2; Tr. 7, at 857-859). Accordingly, the Department finds that the PBR mechanism will result in a reduced administrative burden and is in the public interest as compared to other ratemaking and cost recovery mechanisms (Exhs. NG-PBRP-1, at 9 (Rev.); NG-MLR-1, at 13-14; NG-LRK-1, at 11-12; DPU 54-3 (Supp.)).

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

5. PBR Term

National Grid proposed a PBR term of five years (Exh. NG-PBRP-1, at 28 (Rev.)). The five-year PBR term would commence on October 1, 2021, and expire on September 30, 2026, during which there would be four annual PBR mechanism adjustments, taking effect each October 1, beginning in 2022 (Exh. NG-PBRP-1, at 28 (Rev.)). In conjunction with the PBR term, National Grid proposed a stay-out provision whereby the Company may not file a base distribution rate case during the PBR term that would result in new base distribution rates going into effect earlier than October 1, 2026 (Exh. NG-PBRP-1, at 28 (Rev.)).[48] The Company also proposed a possible five-year extension of the initial five-year term conditioned by an adjustment to base distribution rates during the term extension (Exh. NG-PBRP-1, at 29 (Rev.)).

The Department has found that a well-designed PBR plan should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272. In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 19-120, at 63;

48 The Company conditioned a commitment to the proposed stay-out on two provisions – approval of the proposed PBR mechanism formula without material modification, and approval of the Company’s proposal for recovery of incremental capital additions associated with LNG facility “life-cycle” investments (Exh. NG-PBRP-1, at 29-32 (Rev.)).

D.P.U. 18-150, at 53; D.P.U. 17-05, at 402; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

Previous PBR plans approved by the Department have had terms of five and ten years. See, e.g., D.P.U. 19-120, at 65 (ten years); D.P.U. 18-150, at 56 (five years); D.P.U. 17-05, at 404 (five years); D.T.E 05-27, at 399 (ten years); D.T.E. 03-40, at 495-496 (ten years); D.T.E. 01-56, at 10 (ten years); D.P.U. 96-50 (Phase I) at 320 (five years). With the exception of the PBR plan approved in D.P.U. 96-50 (Phase I), the Department has historically found that five-year terms are not long enough for LDCs to achieve the efficiencies and benefits that a PBR plan is expected to provide to shareholders and ratepayers. D.T.E. 03-40, at 495. However, as discussed below, the circumstances presented in the instant case do not support a PBR term of ten years. Instead, the Department approves a PBR term of five years and denies the Company's proposed option for a term extension.

The Department considered a combination of factors in arriving at this decision. First, the Company has substantial capital investments that it will be undertaking over the course of the next five to ten years, namely two major IT projects (an updated customer information system, or "CIS," and a new back-office platform, referred to as "SAP S/4 HANA") and a series of large-scale, non-routine LNG life-cycle integrity projects (e.g., Exhs. NG-PBRP-1, at 30, 34 (Rev.); NG-ITP-1, at 26-39; NG-GSC-1, at 47, 51-55; DPU 5-12 at 2 & Att. 4 (Supp.); DPU 8-11; DPU 33-6; DPU 54-8). Due to these and other anticipated expenditures, National Grid's current financial projections demonstrate that the

Company would require additional capital support outside of the PBR mechanism (Exhs. NG-PBRP-1, at 30-31, 34 n.8 (Supp.); DPU 5-2; DPU 24-11; DPU 33-7; DPU 48-1 (Supp.); Tr. 4, at 411-413). The Department, however, is not persuaded to approve the Company's additional capital support as proposed in the context of the PBR plan, including cost recovery of LNG life-cycle integrity projects (see Section X below) and the "extended plan" capital roll-in. Second, the frequency of reorganizations by National Grid USA over a relatively short period (at least five in the last 13 years) impacts the Company's organizational continuity and commitment of management and staff (Exh. DPU 53-4, Att. at 32-45; 83, 102-108, 115-119, 181; Tr. 1, at 14-16; see also, Section XII.C.3.c.vii below).[49] For these reasons, the Department is hesitant to allow annual formulaic revenue adjustments over a longer term. Accordingly, the Department finds that a five-year PBR term is appropriate.

The Department, however, reaffirms that a longer PBR term generally coincides with stronger economic incentives, a longer strategic planning horizon, and additional time to accrue administrative efficiencies, supporting the policy that a PBR term of up to ten years, under the right circumstances, is preferrable. Our finding here of a five-year PBR term is grounded in the specific circumstances presented in this case. Further, the Department concludes that a five-year PBR term will allow for the financial and management resources

---

49 The Department notes that the lack of continuity from frequent reorganizations causes disruptions in Company operations, which also could limit the efficiency gains inherent in PBR.

and flexibility necessary for the Company to adjust its operations and investments efficiently, and, in turn, provide ratepayers with the ensuing benefits of increased operational efficiencies, improved service, and avoided administrative costs (Exhs. DPU 5-2; DPU 54-1; DPU 54-3 (Supp.); Tr. 4, at 406-408; Tr. 7 at 851-853, 857-859).

Furthermore, a stay-out provision provides the important benefit to ratepayers of ensuring strong incentives for cost containment under the PBR. D.P.U. 19-120, at 65; D.P.U. 18-150, at 55; D.P.U. 17-05, at 403. Accordingly, the Department adopts a stay-out provision in conjunction with the five-year term.

Based on the foregoing considerations and findings, the Department concludes that the Company's PBR shall operate for a five-year term starting October 1, 2021. Additionally, the Company shall commit to not file a petition under G.L. c. 164, § 94 that results in new base distribution rates going into effect prior to October 1, 2026.[50]

6. Cost Recovery Mechanisms

The Attorney General argues that, if a PBR plan is allowed, the Department should disallow the roll-in of investments that are recovered through capital trackers, including the GSEP charge, the GBE charge, and the proposed LNG and IT charges (Attorney General

[50] In the event that the Company elects to file a petition that results in new base distribution rates going into effect prior to October 1, 2026, no rate factors in effect under the PBR plan shall change during the pendency of the case on that petition, and the PBR plan shall terminate upon issuance of the Department's Order on that petition. If the National Grid ends its PBR plan prior to the end of the five-year term, then, in its next base distribution rate case, the Department will consider any effects of this early termination in setting the Company's ROE.

Brief at 19). The Attorney General notes that 100 percent of these costs already are recovered through the capital trackers (Attorney General Brief at 19). Thus, she contends that allowing these costs to be incorporated into base distribution rates will provide over-recovery of the costs because the costs will be improperly inflated (Attorney General Brief at 19). In this case, the only capital tracker costs being recovered in base distribution revenues adjusted by the PBR mechanism are the costs recovered through the GSEP mechanism (see Section VI.B.6.b below). The Department has found that a PBR mechanism, unlike the GSEP, is not a recovery mechanism intended for recovery of any specific costs. D.P.U. 19-120, at 95-96. In addition, the Department has found that the inclusion of infrastructure replacement costs through the test year in base distribution revenues adjusted by the PBR mechanism is appropriate for the Company's electric affiliates. D.P.U. 18-150, at 72. Therefore, the Department finds that including GSEP costs recovered through the test year in base distribution revenues adjusted by the PBR mechanism is not a concern.

7. Post-Test-Year Capital Additions

As part of the PBR plan, National Grid seeks to roll into rate base its non-GSEP, non-LNG plant additions placed into service between April 1, 2020, through December 31, 2021 (hereafter, "2020 and 2021 capital additions"). The Company proposed the roll in for effect with the first PBR adjustment, October 1, 2022 (Exh. NG-PBRP-1, at 36 (Rev.)). National Grid ties its request to designing PBR cast-off rates that are representative of the Company's current cost basis (Exh. NG-PBRP-1, at 36 (Rev.)). The Company estimates that the 2020 and 2021 capital additions constitute a total of approximately $671.1 million, comprised of $261.4 million in growth investments and $409.8 million in other investments, which include mandated, reliability, and non-infrastructure (tools and equipment) investments (Exhs. NG-PBRP-1, at 38 (Rev.); DPU 5-7; DPU 24-13; DPU 24-14). Of the $671.1 million, 2020 capital additions make up $268.6 million and 2021 capital additions make up $402.5 million (Exhs. NG-PBRP-1, at 38 (Rev.); DPU 5-7). Absent the proposed roll-in, the Company projects that the second-year impact of carrying the 2020 and 2021 capital additions would be a reduction in ROE of 169 basis points excluding growth capital and 277 basis points including growth capital (Exhs. NG-PBRP-1, at 37 (Rev.); DPU 5-9 & Att.; DPU 48-1 (Supp.)).

The Attorney General argues that, if the Department allows a roll-in, it still should disallow the roll-in of capital additions placed into service after the beginning of the rate year (September 30, 2021) because the PBR formula provides for an annual increase in those costs after that point (Attorney General Brief at 18). The Attorney General also asserts that the Company should synchronize capital investments rolled into base rates with the revenues and billing determinants to the same point in time (Attorney General Brief at 18-19).

The circumstances in this case persuade us to consider the Company's post-test-year plant additions, without regard to the size of the additions in relation to rate base. The Company projects significant increases in operating costs and capital investment during the five-year PBR term (Exhs. DPU 5-2; DPU 24-11; DPU 33-6; DPU 54-2; DPU 54-7; AG 21-1, Att. 1; AG 54-45; RR-DPU-27 & Att. at 1, 18). These projected increases stem from expected changes to Company operations and investments to address changes in the gas industry operating environment, including evolving safety requirements and best practices, energy and climate policy, and customer expectations and level of customer engagement (Exhs. NG-PBRP-1, at 15-18 (Rev.); DPU 54-2; Tr. 7, at 860-861). National Grid estimates a change in costs in excess of estimated PBR revenues of approximately $148 million over the three-year period up to October 1, 2024, and $222 million from October 1, 2024 to the end of the five-year plan, without consideration of unplanned or unforeseen cost changes (Exhs. DPU 5-2; DPU 54-2; DPU 54-7; Tr. 7, at 857-861). These costs are comprised of the revenue requirement associated with NGSC allocated rents for IT upgrades, in addition to general O&M, depreciation, and operating tax expense (Exhs. DPU 24-11; DPU 33-6). The Company's capital investment plan over this same period indicates that capital investment will constitute approximately $650 million to $800 million per year, consisting primarily of mandated spending[51] and reliability spending[52] (Exhs. AG 21-1, Att. 1; AG 54-45; DPU 24-14).

---

[51] The Company states that mandated projects include: (1) access protection remediation; (2) corrosion; (3) cross bore protection; (4) high pressure services; (5) cast iron main lining; (6) CISBOT; (7) low pressure system elimination; (8) continuous clamping; (9) main replacement – reactive; (10) integrity management program; (11) integrity verification program; (12) meter purchases; (13) replace pipe on bridges; (14) service replacements; (15) transmission station integrity; and (16) valve installation/replacement (Exh. DPU 24-14).

[52] The Company states that reliability projects include: (1) CNG; (2) distribution station – over pressure protection; (3) gas planning; (4) gas system control; (5) heater installation program; (6) instrumentation & regulation – reactive; (7) pressure regulation engineering – proactive; (8) system automation; (9) take station enhancement program; and (10) water intrusion (Exh. DPU 24-14).

The Company expects for the 2020 and 2021 capital additions to impose substantial carrying costs that will impede its ongoing financial health during the PBR term (Exhs. NG-PBRP-1, at 37 (Rev.); DPU 5-9 & Att.; DPU 48-1 (Supp.); Tr. 7, at 858). Given that the Company expects a continued high level of expenditures during the five-year PBR term, in excess of projected PBR revenue adjustments, the carrying costs of existing capital investments likely will have a persistent impact on the Company's finances (Exhs. NG-PBRP-1, at 37 (Rev.); DPU 5-2; DPU 5-9 & Att.; DPU 24-11; DPU 33-6; DPU 48-1 (Supp.); DPU 54-2; DPU 54-7; AG 21-1, Att. 1; AG 54-45; RR-DPU-27 & Att. at 1, 18). The five-year PBR term and stay-out provision approved above would preclude the Company from seeking a base distribution rate increase to begin recovering the costs of those investments; therefore, the Department finds that it is appropriate to consider the carrying costs in light of the Company's proposed capital additions.

Above, the Department approved a five-year PBR term and stay-out provision, designed to achieve improved operational and administrative efficiencies and associated cost savings to the benefit of ratepayers under the PRB plan. National Grid has demonstrated its commitment to undertaking the operational and capital expenditures necessary to improve the safety and reliability of its distribution system, implement climate policies, and address customer expectations during the PBR term. Further, the Department has found that the PBR plan affords the Company the needed flexibility to address a changing and uncertain operating environment. In light of these circumstances, the Department finds that National Grid has made a convincing showing that a roll-in of capital investments is necessary to create cast-off rates that align more closely with the Company's cost basis, and to ensure that the potential benefits of the PRB plan are realized (Exhs. NG-PBRP-1, at 15-18, 37 (Rev.); DPU 5-2; DPU 5-9 & Att.; DPU 24-11; DPU 24-14; DPU 33-6; DPU 48-1 (Supp.); DPU 54-2; DPU 54-7; AG 21-1, Att. 1; AG 54-45; Tr. 7, at 857-861; RR-DPU-27 & Att. at 1, 18).

The Department, however, is not convinced that a stay-out of five years necessitates a roll-in of 2020 and 2021 capital additions as proposed. The Department seeks to balance establishing appropriate cast-off rates with maintaining a strong incentive for achieving cost efficiencies during the term of the PBR. The Department finds that adding two years of post-test-year capital additions for a five-year PBR term would disproportionately reduce the incentive for achieving cost efficiencies in favor of addressing the impact of the carrying costs to the Company during the stay-out period. Accordingly, the Department allows the Company to roll into rate base capital additions placed into service from April 1, 2020 through December 31, 2020, and denies the Company's proposal to roll into rate base capital additions placed into service from January 1, 2021 through December 31, 2021. The Department directs National Grid to submit supporting documentation and testimony for the 2020 capital additions to demonstrate that the costs associated with the 2020 capital were prudently incurred and that the plant is used and useful to customers. The Company shall provide this information with its PBR plan filing on June 15, 2022, for review and inclusion in rates as of October 1, 2022. The Company shall adjust the base distribution rates for depreciation expense, return on rate base, associated federal and state income taxes, and property taxes, and revenues for all existing 2020 capital assets ending December 31, 2020.

The Company shall also update billing determinants and number of customers as of December 31, 2020. The Department will establish an appropriate procedural schedule to provide interested parties an opportunity to review the project documentation and supporting testimony.

The findings above provide a sufficient basis upon which to allow the Company to incorporate post-test-year plant additions in rate base. We stress that our decision here does not represent a shift in the Department's basic standard for the ratemaking treatment for post-test year plant additions and the required showing of significance.[53] Our treatment of post-test year plant additions is based on the circumstances of this case with our approval of a five-year PBR plan with the specific conditions set forth in this Order.

8. PBR Formula Elements

a. X Factor

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

53 The Department does not recognize post-test year additions or retirements to rate base, unless the utility demonstrates that the addition or retirement represents a significant investment which has a substantial effect on its rate base. Boston Gas Company, D.P.U. 96-50-C at 16-18, 20-21 (1997); D.P.U. 96-50 (Phase I) at 15-16 (1996); Massachusetts-American Water Company, D.P.U. 95-118, at 56, 86 (1996); Western Massachusetts Electric Company, D.P.U. 85-270, at 141 n.21 (1986); Massachusetts-American Water Company, D.P.U. 1700, at 5-6 (1984). See also, Southbridge Water Supply Company v. Department of Public Utilities, 368 Mass. 300 (1975).

differential in expected input price growth between the overall economy and the LDC industry (Exh. NG-MEM/NAC-1, at 13). In combination with the inflation factor, the X factor is designed to represent the expected unit cost performance, or competitive benchmark, in the industry (Exh. NG-MEM/NAC-1, at 19, 31). As described above, National Grid conducted a TFP analysis and ultimately proposed an X factor equal to -1.30 percent (Exhs. DPU 8-8, at 2; DPU 24-17, Att. 1).[54]

The Attorney General argues that the X factor is misspecified due to the inclusion of costs that are otherwise recovered through reconciling mechanisms, including GSEP-related capital additions, LNG production and storage plant, software, pension/PBOPs, among others, which may, she argues, impact the magnitude of the X factor (Attorney General Brief at 19-20). The Attorney General does not provide an alternative X factor for the Department's consideration. The Company argues that cost recovery mechanisms are not relevant for the calculation of TFP, and, therefore, the calculation of the X factor (Company Brief at 58).

The Company calculated TFP and corresponding X factors using two different samples for its productivity study: (1) a sample of 85 U.S. LDCs intended to represent the overall nationwide LDC industry; and (2) a sample of 29 LDCs intended to represent the LDC industry in the Northeast (Exhs. NG-MEM/NAC-1, at 21, App. A at 16-17; DPU 8-4;

54 The Company initially proposed an X factor of -1.19 percent, but during the proceeding updated the proposal to -1.30 percent based on a correction to the Company's TFP study (Exhs. NG-MEM/NAC-1, at 30-36; DPU 8-8).

DPU 24-15). The Company proposed that the X factor corresponding to the Northeast sample, -1.30 percent, be incorporated into the PBR mechanism due to differences in growth in the output and input components of TFP between the national sample and the Northeast sample (Exh. NG-MEM/NAC-1, at 32). The Company also cited differences in infrastructure and population density in the Northeast, which impact operating costs, as a reason to use the Northeast regional X factor (Exh. NG-MEM/NAC-1, at 33-36).

The Department recognizes that TFP growth differs between the national and Northeast regional group for a variety of reasons. Differences in economies of scale, technology, input and output growth, population density, system size, and system composition influence trends in TFP over time. We find that the Company has demonstrated that the LDCs in the Northeast have characteristics that differ from LDCs in the rest of the United States such that the Northeast regional peer group is more appropriate for the purpose of setting an X factor (Exh. NG-MEM/NAC-1, at 32-36; Tr. 5, at 603-605).

With respect to the impact of including costs being recovered through reconciling mechanisms (including GSEP costs) in the calculation of TFP, the Department recognizes that the method of cost recovery for any subset of costs should not bear on the industry-wide estimation of productivity. The TFP study is designed to measure the expected rate of change in productivity, or the relationship of total output to total input for the LDC industry (Exh. NG-MEM/NAC-1, at 13, 36-37; Tr. 5, at 599).[55] The resulting X factor functions as

---

55 Specifically, regarding the impact of GSEP capital on the X factor, the Department is satisfied that, even if the data were available to do a calculation to account for GSEP

a measure of economic performance that is external to the Company (Exh. NG-MEM/NAC-1, at 7). Therefore, whether costs included in the measure of total input are recovered separately for one or more LDCs in the study sample should not affect the accuracy of the measure of industry productivity (Exh. DPU 48-4; Tr. 5, at 599-600).

The Department has historically found that regional peer groups are appropriate for setting X factors for LDCs. D.P.U. 19-120, at 81; D.T.E. 05-27, at 363; D.T.E. 03-40, at 475; D.P.U. 96-50 (Phase I) at 275-276. The evidence provided in the instant proceeding is consistent with the Department's past findings. We find that the use of a Northeast regional peer group is consistent with Department precedent and that conditions in the Northeast are unique enough to determine that the Northeast region LDCs are closer peers to National Grid than the national LDC sample. Moreover, the Northeast regional peer group accounted for 80 percent of gas customers in the Northeast region and 93.4 percent of the total volume of gas sales as of 2018, which the Department finds is sufficiently robust, providing a reliable basis to establish TFP (Exhs. NG-MEM/NAC-1, App. A, at 16; DPU 8-6; DPU 8-5 Att.). Accordingly, the Department accepts the Company's reliance on the Northeast peer group for establishing an appropriate X factor.

As discussed above, the Department reviewed the Company's proposed TFP study, which generates an X factor of -1.30 percent. The Department finds that National Grid's

capital, it would be unlikely to bias the X factor in either direction (Exh. NG-MEM/NAC-1, at 36-37; Tr. 5, at 635-642).

study as a whole is reasonable. Accordingly, the Department approves the Company's proposed X factor of -1.30 percent based on a Northeast regional sample.

b. Consumer Dividend

i. Introduction

The consumer dividend is intended to reflect expected future gains in productivity because of the move from cost of service regulation to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166, 280. As a deduction to the PBR adjustment, the consumer dividend is a commitment by the Company to share these productivity gains with customers (Exh. NG-LRK-1, at 50). The Department has found that a consumer dividend represents an explicit, tangible ratepayer benefit. D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395.

National Grid proposes to apply a consumer dividend of 0.15 percent as part of the PBR mechanism (Exhs. NG-PBRP-1, at 12 (Rev.); NG-LRK-1, at 51). The Company conducted a benchmarking study and determined that National Grid is a superior cost performer in the provision of gas distribution services (Exhs. NG-LRK-1, at 58; NG-LRK-2, at 24). The Attorney General argues that there are several methodological concerns with how the Company conducted the benchmarking study; the Attorney General conducted a revised benchmarking analysis addressing these concerns (Attorney General Brief at 22-23, citing Exh. AG-DED-1, at 48; RR-AG-13; Attorney General Reply Brief at 13). The Attorney General concludes that, contrary to the Company's assertion, National Grid's cost performance is poor relative to peers and particularly poor compared to NSTAR Gas (Exh. AG-DED-1, at 55). As noted in n.38 above and discussed further below, the Attorney

General offers an alternative benchmarking analysis and arrives at a recommended consumer dividend of 0.30 percent (Exh. AG-DED-1, at 45-55).

Next, the Department weighs the arguments regarding the differing benchmarking methodologies employed.

ii. Peer Group

National Grid's benchmarking analysis included three peer groups: (1) a national sample of 85 companies; (2) a Northeast sample of 29 companies; and (3) an urban peer group of four companies (Exhs. NG-MEM/NAC-1, at 21, App. A at 16-17; NG-LRK-2, at 10-11; DPU 8-4; DPU 24-15). The national and Northeast samples are comprised of utilities for which the appropriate data was available (Exhs. DPU 8-4; DPU 24-15). The Northeast sample specifically is comprised of utilities from eight states, and according to the Company, is consistent with Department precedent for selecting a regional benchmarking sample (Exhs. DPU 8-4; DPU 24-15). The Company selected the urban peer group to represent peers with similar business conditions, based on the criteria that they have aging assets, serve central business districts or densely populated areas, and are located in "mature" or long-settled, big cities (Exhs. NG-LRK-2, at 10; DPU 24-1). The Attorney General's alternative benchmarking analysis used a sample of 20 large utilities, defined as serving 200,000 customers or more, from four states in the Northeast identified as having a high proportion of mains prioritized for replacement due to their composition (e.g., cast iron or bare steel) (Exh. AG-DED-1, at 46; Tr. 11, at 1199-1201). The Attorney General states that the sample used in her alternative analysis focuses on gas distributors that are geographically similar and of similar size in terms of the number of customers, and that, conversely, the sample relied upon by the Company includes many small natural gas systems that may have more limited efficiencies of scale when compared to the Company (Exhs. DPU-AG 1-3; NG-AG 1-24).

The Attorney General takes issue with the Company's comparison of its cost efficiency to the urban peer group of four utilities, specifically because it spans a limited geographic area, it contains only three non-affiliated companies, and, according to the Attorney General, the Department has historically not placed weight on such limited peer groups (Attorney General Brief at 24). The Company claims that the peer group used in the Attorney General's benchmarking analysis does not account for the set of unique business conditions that its urban peer group seeks to correct for, and that not making such a correction risks mistaking a challenging service territory for inefficiencies (Exh. NG-LRK-1, at 55-56; Company Brief at 66, citing Exh. NG-LRK-Rebuttal-1, at 21; Company Reply Brief at 23).

The Attorney General and National Grid both consider a set of pipeline replacement data presented by the Company to assess whether the peer groups selected by each demonstrate the purportedly unique infrastructure challenges facing the Company (RR-DPU-15). The Attorney General claims that, based on the data, replacing aging infrastructure is not unique to National Grid and urban peers, and instead that non-urban companies also have decreased the inventory of cast iron and bare steel mains (Attorney General Brief at 29-30; Attorney General Reply Brief at 14). The Company responds that the Attorney General's peer group did not account for the unique cost challenges facing the Company, pointing to the data that Boston Gas and the urban peer group have been more active in replacing cast iron and bare steel assets when compared to the other companies in Attorney General's regional sample of utilities (Exh. NG-LRK-Rebuttal-1, at 19-21; RR-AG-15; Company Brief at 68).

The Department has noted that econometric benchmarking is a preferred method for controlling for differing circumstances between companies in a sample. D.P.U. 18-150, at 62 n.26. Unit cost benchmarking does not control for differences in business conditions across firms in the sample (Exh. DPU 4-1). The Company, however, chose not to conduct an econometric benchmarking study, and, instead, used the urban peer group to provide a comparison of the Company to a group of utilities facing similar operating conditions (Exhs. DPU 4-1; DPU 4-2; Tr. 5, at 629-632). While the Department recognizes that National Grid may face challenging business conditions due to the composition of its pipeline infrastructure and service territory, the Company did not provide underlying data and statistical results to support the selection of the urban peer group used to control for those conditions (Exh. DPU 24-1). Conversely, the Attorney General's approach to selecting a peer group provided a data-driven method of identifying peers, namely by using both number of customers and Pipeline Hazardous Materials Safety Administration ("PHMSA") data on the proportion of high-risk pipeline in each state (Exh. AG-DED-1, at 46; Tr. 11, at 1199-1201). While the Company's Northeast sample is consistent with Department precedent for selecting a regional benchmarking sample for the gas distribution industry, the use of a unit cost approach instead of an econometric approach does not allow for the analysis to control for factors such as company size, which, as the Attorney General suggests, may impact the results (Exhs. DPU 8-4; DPU 24-15; NG-AG 1-24). D.P.U. 19-120, at 24-25.

iii. Time Period of Analysis

The Company used data from the most recent three years available to conduct its benchmarking analysis, 2016-2018 (Exhs. NG-LRK-2, at 15; Tr. 5, at 633-634). The Attorney General presents her alternative analysis for a period of five years and ten years, claiming that the longer time frames are consistent with the proposed PBR term and will prevent the results from being influenced by a handful of smaller observations (Exh. AG-DED-1, at 39; Attorney General Brief at 26, 29).

The Company argues that using a three-year period of analysis for benchmarking is standard practice for a benchmarking study, reflects that the consumer dividend is forward-looking and appropriate for capturing current cost efficiency at the outset of a PBR, and is consistent with Department precedent (Company Brief at 64, citing Exhs. NG-LRK-Rebuttal-1, at 23; AG 3-11). The Attorney General indicates that the Company's use of a period of three years is limited and inconsistent with other parts of its analysis in support of a PBR, namely the analysis of main replacement data over ten years and the TFP study over 15 years of data (Attorney General Brief at 26; Exh. AG-DED-1, at 38). The Company responds that the Attorney General's assertion that using a three-year period for benchmarking is problematic is the result of a misunderstanding of prior studies (Company Brief at 63-64).

The Department has relied on benchmarking studies that analyze a period of three to four years. D.P.U. 19-120, at 85-86 & Exh. ES-JF/MF-3, at 17 (four years); D.P.U. 18-150, at 62 (three years). The Department finds that using data on a company's recent past performance is reasonable given that the consumer dividend is intended to be a forward-looking factor, estimating expected future gains in productivity. The Department also finds that using three or four years of data is sufficient to protect against the results being impacted by short-term anomalies. The Department, therefore, finds that the Company's choice of a three-year sample period is appropriate.[56]

iv. Output Metric

The Company's benchmarking study analyzes total cost and TFP on a per-customer basis and references the use of customers as the sole output metric used in the TFP study (Exh. NG-LRK-2, at 7-8). The Attorney General's alternative benchmarking analysis presents unit cost on a per-customer and per-Mcf basis and uses throughput as a measure of volumetric demand (Exh. AG-DED-1, at 43-47).

The Attorney General claims that the Company's exclusive reliance on number of customers as a measure of output does not reflect the cost causation considerations that are used in a typical "Class Cost of Service Study," which would, instead, classify distribution

56 The results of the Company's analysis do not change substantially whether a period of three years or four years is used (RR-AG-17).

costs as demand-driven (Attorney General Brief at 27). The Company contends that the benchmarking results provided by the Attorney General that use throughput as an output metric should be disregarded since it is peak demand and not total throughput that is the relevant volume-related cost driver, particularly since using delivery volume undermines demand resource and energy efficiency goals (Company Brief at 63). The Attorney General maintains that throughput is related to peak demand (Attorney General Brief at 28).

The Department agrees that considering volume as an output metric is a potentially useful exercise, and notes that total throughput is not equivalent to peak demand. Further, we find that it is peak demand and not total throughput that would appropriately reflect volume-related costs, because peak demand is the metric used to appropriately size distribution systems (Exhs. NG-LRK-Rebuttal-1, at 3; AG-DED-1, at 43, 45; AG 3-9; Tr. 5, at 571-572; Tr. 11, at 1203). The Department also recognizes that data on peak-day demand is not readily available for use in this type of analysis (Tr. 5, at 622-623; Tr. 11, at 1203). We also note that the results of the Attorney General's benchmarking analysis did not change substantially when standardized by volume as opposed to number of customers (Tr. 11, at 1202).

v. Benchmarking Costs

The Company and the Attorney General disagree on the costs that should be included in the benchmarking analysis. The Company's benchmarking analysis uses a measure of total cost, including capital, labor, and materials (Exh. NG-LRK-2, at 7). The Company's measure of capital costs is developed based on estimates of quantity and price and uses a perpetual inventory equation for quantity and an implicit rental price formula for price (Exh. NG-MEM/NAC-1, App. A, at 8-12). When incorporating administrative and general ("A&G") expenses, the Company allocates a portion of the total amount of A&G, apportioned based on the ratio of distribution plant to total plant across the sample, to reflect the fact that only a portion of A&G expenses are attributable to the distribution function of the business (Exh. NG-MEM/NAC-1, App. A, at 7-8; Tr. 5, at 643-645; RR-DPU-30). The Attorney General's alternative study analyzes operating expense performance, exclusive of capital costs, to indicate that operating expenses are an appropriate signal of a utility's cost performance and relative efficiency and are more easily comparable between utilities due to uniform reporting (Exhs. AG-DED-1, at 46; DPU-AG 1-4; NG-AG 1-29). The Attorney General's operating expenses, however, include total A&G expenses, of which she states the Company inappropriately omits a portion (Exh. AG-DED-1, at 37, 46). The Attorney General also notes that she was unable to develop a measure of capital costs, in part due to the detailed and involved nature of the calculations (Exh. DPU-AG 1-4). As an alternative, the Attorney General provides an analysis of net utility plant (Exh. DPU-AG 1-4 & Att.). The Attorney General maintains that capital costs are appropriately excluded from her benchmarking analysis because major capital expenses are recovered outside of the PBR mechanism (Attorney General Brief at 28-29).

The Department disagrees with the Attorney General that capital costs should not be included in a benchmarking study. The Department has reviewed and relied on total cost benchmarking studies in support of prior consumer dividend findings. D.P.U. 19-120, at 83-86; D.P.U. 18-150, at 61-62; D.P.U. 05-27, at 391-393.[57] The gas distribution industry is a capital-intensive industry and including capital costs in a benchmarking study will appropriately reflect a Company's relative cost efficiency. The Attorney General's alternative analysis of net utility plant indicates that the Company deploys relatively more capital on a per-customer and per-volume basis compared to regional peers – this analysis does not, however, speak to capital cost efficiency (Exh. DPU-AG 1-4 & Att.; Tr. 11, at 1204-1206). Therefore, the Department finds that including capital costs in a benchmarking analysis is appropriate. Regarding the treatment of A&G expenses, the Department finds that the Company's method of apportioning A&G expenses is reasonable since the full amount of A&G would not be attributable to the distribution functions of the Company (Exhs. NG-MEM/NAC-1, at 2-4; NG-MEM/NAC-1, App. A, at 7-8).

vi. Conclusion

The two benchmarking studies report vastly different results for the Company in terms of relative cost efficiency (Exhs. NG-LRK-1, at 54; AG-DED-1, at 51). There are numerous differences between the two studies and, due to the reasons discussed above, the Department does not find that either study is alone sufficient to determine the relative cost performance of

[57] In D.T.E. 03-40, at 483-484, the Department found that the estimate of capital costs provided in the benchmarking study was problematic, specifically, that Boston Gas did not demonstrate that the vintaging of benchmark capital stock was not systematically biased. In D.P.U. 19-120, at 83-84, 86, the Department found the vintaging methods employed to be appropriate. The methods used in the instant matter are similar to those applied in D.P.U. 19-120 (Exh. NG-MEM/NAC-1, App. A, at 10). D.P.U. 19-120, Exh. ES-JF/MF-2, at 34-35.

the Company. For instance, the Company's analysis may fail to account for differences in company size, and, while the Attorney General's sample may do so, her analysis does not include all relevant costs. Both analyses, however, agree that NSTAR Gas outperforms National Grid in terms of cost efficiency (Exhs. NG-LRK-1, at 54; AG-DED-1, at 51). Furthermore, the Company notes that a comparison between the two companies is particularly salient with respect to benchmarking evaluations and their implications for appropriate consumer dividend levels (Exh. DPU 24-4). Based on the Company's findings, the difference in relative unit cost between 2016 and 2018 of over 40 percent between the two companies is considerable (RR-AG-13). Likewise, the Attorney General finds that, based on a five-year average, the Company's total expenses were more than double those of NSTAR Gas on a per-customer basis (Exh. AG-DED-7, at 3).[58] In addition, based on data provided by the Company, when compared to NSTAR Gas, the Company does not appear to have undertaken substantially more pipeline replacement. Over the three-year period from 2016 to 2018, it appears that total steel and cast-iron pipeline replacement for the Company and NSTAR Gas are 4.3 percent and 3.6 percent relative to total 2018 pipeline miles, respectively (Exh. DPU 4-3, Att. 2).[59]

---

[58] The five-year average total expenses per customer for the Company are $536 and the equivalent for NSTAR Gas are $265 (Exh. AG-DED-7, at 3). If only the most recent three years of data are used (2017-2019), average total expenses for the Company are $611 and the equivalent for NSTAR Gas are $267 (see Exh. AG-DED-7, at 3).

[59] Boston Gas replaced 132 miles of steel and 153 miles of cast iron between 2016 and 2018, and in 2018 had 6,370 total miles of pipeline. The former Colonial Gas replaced 40 miles of steel and nine miles of cast iron between 2016 and 2018, and in 2018 had 1,402 total miles of pipeline. Together, the Company therefore replaced

Based on these considerations and findings, the Department is not convinced that National Grid is a comparable cost performer to NSTAR Gas. Accordingly, we reject the Company's proposal to assign a consumer dividend equivalent to that of NSTAR Gas. Instead, based on the Company's higher cost performance, the Department finds that a consumer dividend greater than 0.15 percent is appropriate.

Next, the Department must decide the appropriate magnitude of a consumer dividend. The Department has approved a consumer dividend of 0.40 percent for a company that qualified as an average cost performer. D.P.U. 18-150, at 61-62, citing D.T.E. 05-27, at 393. In addition, an assessment of the potential cost efficiencies gained during a PBR in Massachusetts found that 0.30 percent cost savings can be achieved over a period of less than five years (Exh. NG-LRK-1, at 12-14; Tr. 5, at 612). D.T.E. 03-40, at 487 (finding that 0.30 percent cost saving was the minimum cost saving that Boston Gas achieved solely as a result of its PBR plan). Further, while a higher consumer dividend will result in greater immediate returns to customers, and a greater incentive for the Company to achieve further cost reductions and productivity gains under the PBR plan, these incentives must be balanced against the need for the Company to earn sufficient revenue so that it can provide reliable service to customers. Based on these considerations, the Department finds that a consumer dividend of 0.30 percent is appropriate to provide an immediate ratepayer benefit.

---

334 miles relative to 7,772 total miles, or 4.3 percent. NSTAR Gas replaced 68 miles of steel and 51 miles of cast iron between 2016 and 2018, and in 2018 had 3,292 total miles of pipeline, and therefore replaced 119 miles relative to 3,292 total miles, or 3.6 percent (Exh. DPU 4-3, Att. 2).

Accordingly, the Department directs the Company to incorporate a consumer dividend of 0.30 percent in its PBR formula.

c. Exogenous Cost Factor

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

National Grid proposes to adopt a two-part exogenous cost mechanism (Exhs. NG-PBRP-1, at 24-25 (Rev.); NG-PP-10, proposed M.D.P.U. No. 56, § 10.0). The first part is consistent with the definition adopted by the Department in D.P.U. 94-50 (Exhs. NG-PBRP-1, at 24-25 (Rev.); NG-PP-10, proposed M.D.P.U. No. 56, § 10.0). Accordingly, the Department finds that the Company's proposed definition of exogenous costs in this instance is appropriate, with one amendment. The Department has found that further specifying the definition of the relevant industry may more reliably distinguish changes that are not reflected in GDP-PI. See D.P.U. 96-50 (Phase I) at 289-290. Therefore, the Company shall further specify the relevant industry to be the regional natural gas distribution industry (Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 10.0(3)).

The second part is a more targeted definition specific to exogenous events arising due to pipeline safety requirements imposed after November 13, 2020, with demonstrated cost impacts after the effective date of the PBR mechanism on October 1, 2021 (Exhs. NG-PBRP-1, at 24-25 (Rev.); NG-PP-10, proposed M.D.P.U. No. 56, § 10.0). The Company contends that this additional definition is necessary in order to manage some of the uncertainty that the Company expects to encounter over the term of the PBR Plan (Exhs. NG-PBRP-1, at 25-26 (Rev.); DPU 5-5, at 2). While some pipeline safety requirements may arise from regulatory, judicial, or legislative changes and would be captured under the traditional mechanism, the proposed secondary definition is designed also to capture exogenous events that arise from other recommendations or directives that lead to costly institutional changes requiring the Company to modify its operating practices and protocols (Exh. DPU 5-5, at 1-2). The Department finds that future uncertainty in the natural gas distribution industry, particularly with respect to changes in requirements stemming from the Merrimack Valley incident, warrant a consideration for additional exogenous costs that may arise above and beyond those experienced in the past. Therefore, the Department accepts the Company's proposed two-part definition of the exogenous cost factor.

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

National Grid has proposed an exogenous cost significance threshold of $2 million for the first PBR year, ending September 30, 2022, subject to annual adjustments thereafter based on changes in GDP-PI (Exhs. NG-PBRP-1, at 25 (Rev.); NG-PP-10, proposed M.D.P.U. No. 56 § 10.0).[60] The Company proposed different treatments of the eligible costs under the two proposed parts of the definition of an exogenous event: (1) the significance threshold for the first part, the traditional exogenous cost factor, would include annual O&M cost changes, and (2) the significance threshold for the second part, specific to

60 The Company calculated the $2 million threshold based on calendar year 2019 total operating revenues of $1.571 billion (Exhs. NG-PBRP-1, at 25 (Rev.)). However, in prior decisions, including those with a non-calendar test year, the Department has relied on test-year operating revenues in the calculation of the significance threshold. D.P.U. 19-120, at 93; D.P.U. 18-150, at 66; D.P.U. 17-05, at 397. If the significance threshold calculation instead were to use the total test-year operating revenues of $1.556 billion, we find that a $2 million significance threshold still would be acceptable (Exh. NG-RRP-2, Sch. 1, at 3 (Rev. 3)).

pipeline safety requirements, would allow for both capital and O&M cost changes, applied separately to annual O&M cost changes and to the annual revenue requirement on cumulative capital investment (Exh. DPU 54-4).[61] Although the Department must consider the facts and circumstances of each case, the Department has found that an exogenous cost significance threshold was reasonable where it was equal to a multiple of 0.001253 times a company's total operating revenues. D.P.U. 19-120, at 93-94; D.P.U. 18-150, at 66-67; D.P.U. 17-05, at 397; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-26; D.P.U. 98-128, at 53-56; D.P.U. 96-50 (Phase I) at 293.

As discussed above, the Department allowed the Company to roll-in prudently incurred 2020 capital additions during the PBR term. Due to this adjustment, we do not find it appropriate to incorporate a second method to collect the costs of capital additions during the PBR plan. D.P.U. 19-120, at 93. Therefore, the Department will allow the Company only to file for exogenous costs on O&M cost changes and not file for adjustments to the annual revenue requirement of cumulative capital investment. Consistent with our precedent and the facts of this case, the Department finds that $2 million is a reasonable exogenous cost significance threshold for National Grid, which has total test year operating revenues of

---

61 The Company's PBR Panel testimony appears more broadly worded, as it describes a threshold that is cumulative under either definition of exogenous event (Exhs. NG-PBRP-1, at 25 (Rev.)). The Department, however, understands the significance threshold as applied to annual O&M cost changes to be based on noncumulative costs (Exhs. NG-PP-10, proposed M.D.P.U. No. 56, § 10.0).

$1.556 billion and is implementing a multi-year PBR plan of the overall design approved herein.[62]

In addition, the Company has proposed that the exogenous cost significance threshold be subject to annual adjustments based on changes in GDP-PI as measured by the U.S. Department of Commerce (Exh. NG-PBRP-1, at 25 (Rev.)). The Department is satisfied that this proposal appropriately considers the effects that inflation will have on the threshold in the later years of the PBR term. D.P.U. 19-120, at 94; D.P.U. 18-150, at 67; D.P.U. 17-05, at 398; D.T.E. 01-56, at 11-14; D.P.U. 98-128, at 57. Accordingly, we set the Company's threshold for exogenous cost recovery at $2 million for each individual event in the first PBR year, ending September 30, 2022, subject to annual adjustments thereafter based on changes in GDP-PI as used in the PBR mechanism. Based on the foregoing analysis, the Department approves the Company's proposed exogenous cost factor with modifications as a component of the PBR mechanism.

Exogenous cost recovery requires that a company provide supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed exogenous cost. D.T.E. 99-19, at 25; D.P.U. 98-128, at 55; Bay State Gas Company, D.T.E. 98-31, at 17-18 (1998). Additionally, any company seeking recovery of an exogenous cost bears the burden of demonstrating the propriety of the exogenous cost and that the proposed exogenous cost change is not otherwise reflected in the GDP-PI.

---

62 Multiplying National Grid's total test-year operating revenues of $1,556,218,872 by a factor of 0.001253 equals $1,949,942.

D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 171. For these reasons, the Department does not prejudge the qualification of any future events as exogenous costs and will consider each proposal for recovery of exogenous costs on a case-by-case basis. At the time that it seeks exogenous cost recovery, National Grid must demonstrate that the event meets both the definition and threshold for exogenous costs approved herein. Moreover, with respect to the second category of qualifying costs, National Grid must demonstrate that the proposed costs for recovery are above and beyond the types of costs that the Company normally incurs for safety and reliability.[63]

d. Earnings Sharing Mechanism

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

The Company proposes to implement an asymmetrical ESM with a deadband of 100 basis points above and 150 basis points below the allowed ROE (Exh. NG-PBRP-1, at 26 (Rev.)). The proposed ESM would trigger a sharing of earnings with customers on a 75 (customers)/25 (shareholders) basis when the actual ROE exceeds 100 basis points above the allowed ROE (Exh. NG-PBRP-1, at 26 (Rev.)). If the actual ROE is below the allowed ROE, the shortfall would be shared on a 50/50 basis between customers and shareholders if

63 The Department discusses the Company's exogenous cost property tax proposal in Section IX below.

the shortfall is between 150 and 200 basis points below the allowed ROE, and on a 75 (customers)/25 (shareholders) basis if the shortfall exceeds 200 basis points below the allowed ROE (Exh. NG-PBRP-1, at 26-27 (Rev.)).

An ESM offers an important protection for ratepayers in the event that expenses increase at a rate much lower than the revenue increases generated by the PBR. D.P.U. 19-120, at 87; D.P.U. 18-150, at 70; D.P.U. 17-05, at 400; D.P.U. 10-70, at 8 n.3; D.T.E. 05-27, at 404-405. For this reason, the Department finds that there is a significant benefit to implementing an ESM as part of the PBR plan approved in this case. As discussed below, the Department finds that certain modifications to the Company's proposed ESM are necessary to appropriately balance the risks to shareholders and ratepayers under the PBR plan.

The Department finds that an asymmetrical deadband appropriately protects ratepayers, is consistent with recent Department precedent, and further increases the Company's incentive to pursue savings, as a greater share of under-earnings will be borne by the Company. D.P.U. 19-120, at 88; D.P.U. 18-150, at 71-72; D.P.U. 17-05 at 401. In contrast, a symmetrical deadband may inappropriately shift losses to ratepayers.

As noted above, the Company proposed to adopt a deadband of 100 basis points above and 150 basis points below the allowed ROE (Exh. NG-PBRP-1, at 26 (Rev.)). The Department has approved ESMs with deadbands of 100 basis points or greater. D.P.U. 19-120, at 89; D.P.U. 18-150, at 71-72; D.P.U. 17-05, at 401; D.T.E. 05-27, at 405; D.T.E. 03-40, at 500; D.P.U. 96-50 (Phase I) at 326. National Grid argues that an asymmetrical ESM provides customers with a near-term benefit if gains are produced above the deadband level and allows for adjustments if the PBR mechanism results in earnings that are out of alignment with the Company's costs (Company Brief at 28). The Company further notes that the proposed ESM is identical to ESM approved in D.P.U. 19-120 (Company Brief at 28-29).

As discussed above, the Department has approved a PBR term of five years. In prior PBR plans with terms of five years, the Department has found that a one-sided PBR with a deadband of 200 basis points was reasonable. D.P.U. 18-150, at 70-71; D.P.U. 17-05, at 400-401. In the instant case, the Department finds that a 200-basis point deadband above the allowed ROE and no sharing if earnings fall below the authorized ROE also is reasonable. In particular, the Department finds that an asymmetrical deadband of 200 basis points above the allowed ROE will provide the Company with a strong incentive to pursue savings.

Further, to appropriately balance shareholder and ratepayer risk under the PBR mechanism as designed, the Department finds that the benefits of any earnings above the deadband must inure largely to ratepayers. Accordingly, we find that a mechanism that shares earnings with ratepayers and shareholders on a 75/25 percent basis (i.e., 75 percent to ratepayers and 25 percent to shareholders) for earnings more than 200 basis points above the allowed ROE is appropriate in this case. This ratio will provide National Grid an adequate incentive to pursue savings while protecting ratepayers from any unforeseen financial windfall for the Company as a result of the implementation of the PBR plan.

Accordingly, the Department finds that the Company's PBR mechanism shall include an asymmetrical ESM that sets a deadband of 200 basis points above the Company's allowed ROE. If National Grid's actual ROE falls within the deadband, there will be no sharing. If the Company's actual ROE exceeds the allowed ROE by more than 200 basis points, the earnings above the deadband will be shared 75 percent with ratepayers and 25 percent with shareholders.

9. Conclusion

In the sections above, the Department has reviewed the Company's PBR proposal and has found that, as approved, it is more likely than current regulation to advance the Department's goals of safe, secure, reliable, equitable, and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. G.L. c. 25, § 1A. In addition, the Department has found that the proposed PBR plan, as approved, will provide National Grid with greater incentives to reduce costs than currently exist and should result in benefits to customers that are greater than would be present under current regulation. Further, the Department has found that the proposed PBR plan, as approved, better satisfies our public policy goals and statutory obligations, including promotion of a safe and reliable gas pipeline infrastructure, and of the Commonwealth's clean energy goals and mandates.

With the modifications required herein, the Department finds that the PBR mechanism appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Accordingly, the Department approves National Grid's proposed PBR plan, subject to the modifications above. National Grid, in its compliance filing, shall submit a revised PBR provision tariff consistent with the findings in this Order.

Further, National Grid shall submit an annual PBR adjustment filing, including all information and supporting schedules necessary for the Department to review the proposed PBR mechanism adjustment for the subsequent rate year. Such information shall include the results and supporting calculations of the PBR mechanism adjustment factor formula, descriptions and accounting of any exogenous events, and an earnings sharing credit calculation for the year, two years prior to the rate adjustment. In addition, National Grid shall file revised summary rate tables reflecting the impact of applying the base distribution rate changes provided in the PBR mechanism adjustment filing. National Grid shall submit its annual PBR mechanism adjustment filing on or before June 15 of each year, commencing in 2022 and continuing for the five-year term of the PBR Plan. Consistent with our findings above, the PBR Plan shall continue in effect for a total of five consecutive years starting October 1, 2021, with the last adjustment taking effect on October 1, 2025, and with the PBR mechanism expiring on September 30, 2026.

V. PERFORMANCE INCENTIVE MECHANISMS AND SCORECARD METRICS

A. Introduction

As noted in Section IV.A above, the Company proposes PIMs and scorecard metrics as elements of its PBR plan (Exh. NG-PBRP-1, at 11-12 (Rev.)). The Company states that its proposed PIMs are intended as motivation to achieve policy goals set forth by the

Department and the Commonwealth that may be uneconomic or impractical to pursue without a financial incentive (Exh. NG-PBRP-1, at 12, 42 (Rev.)). As discussed in further detail below, the two specific PIMs proposed by the Company are: (1) leak backlog reduction; and (2) non-pipeline alternatives shared saving mechanism ("non-pipeline alternative") (Exh. NG-PBRP-1, Table 1, at 43 (Rev.)).

National Grid states that its proposed scorecard metrics are intended to allow the Department and key stakeholders to evaluate the effectiveness of the Company's operational performance during the five-year PBR term (Exhs. NG-PBRP-1, at 69; NG-PBRP-1, at 12 (Rev.)). As discussed in further detail below, the proposed scorecard metrics fall into three general categories: safety and reliability; customer satisfaction and engagement; and emissions reduction (Exh. NG-PBRP-1, at 62 (Rev.)). The Company proposes a total of eight scorecard metrics: (1) damage prevention; (2) American Petroleum Institute ("API") 1173 maturity score; (3) web user experience index; (4) customer adoption of digital bill pay; (5) first contact resolution; (6) average speed of answer; (7) new gas customer connections; and (8) methane emissions (Exh. NG-PBRP-1, Table 4, at 62-63 (Rev.)).

The Company proposes to report on its performance on PIMS and scorecard metrics as part of the annual PBR plan filings (Exh. NG-PBRP-1, at 35 (Rev.)). The Company proposes that the reporting of the PIMs and scorecard metrics, along with the recovery of the PIMs incentives, if applicable, would begin in the June 15, 2023, PBR plan filing and continue through the June 15, 2027, filing (Exh. NG-PBRP-1, at 35 (Rev.)).

B. Company Proposals

1. PIMs

a. Introduction

The Company states that the purpose of a PIM is to better align the utility's regulatory and financial interests with the interests of the public (Exh. NG-PBRP-1, at 42 (Rev.)). According to the Company, a PIM provides a regulated utility with a financial incentive to pursue an outcome aligned with a public policy objective, shared by regulators and key stakeholders, that typically falls outside of the utility's core service obligations and may be uneconomic or impractical for the utility to pursue otherwise (Exh. NG-PBRP-1, at 42 (Rev.)). The Company states that a PIM also may provide a utility with an incentive to drive outperformance in areas that go above and beyond its public service obligations (Exh. NG-PBRP-1, at 42 (Rev.)). As noted above, the Company proposes PIMs to address leak backlogs and non-pipeline alternatives.

b. Leak Backlog Reduction

The Company states that natural gas leaks on its distribution infrastructure are classified by their severity as Grade 1, Grade 2, or Grade 3 leaks (Exh. NG-PBRP-1, at 46 (Rev.)). Grade 1 leaks are hazardous and are required to be repaired immediately or to be continuously monitored until repaired; and Grade 2 leaks may become hazardous and are required to be repaired within twelve months (Exh. NG-PBRP-1, at 46 (Rev.)). Grade 3 leaks are non-hazardous and are further classified as environmentally significant or as non-environmentally significant dependent on barhole readings and leak extent

(Exh. NG-PBRP-1, at 46 (Rev.)). Grade 3 leaks discovered prior to January 1, 2018, do not have a required repair timeline, but those discovered on or after January 1, 2018, must be repaired within eight years of discovery (Exh. NG-PBRP-1, at 47 (Rev.), citing 220 CMR 114.04(3)(c) and 220 CMR 114(4)).

The Company's proposed leak backlog reduction PIM targets Grade 3 non-environmentally significant leaks on the Company's distribution system (Exh. NG-PBRP-1, at 45 (Rev.)). Additionally, repair of a non-environmentally significant Grade 3 leak will count only toward the PIM target if the leak was discovered prior to 2018, or if the leak was discovered in 2018 or later but repaired before the allowed eight-year timeline for repair (Exh. NG-PBRP-1, at 47 (Rev.)). The Company proposes to set the leak backlog reduction PIM baseline at 425 non-environmentally significant leaks, which is the amount repaired in the test year out of an inventory of 8,900 Grade 3 leaks in the Company's service territory (Exh. NG-PBRP-1, at 47 (Rev.)). For every 100 leaks repaired above this baseline, the Company proposes to earn an incentive equal to one half of one basis point of earnings on a pre-tax basis (Exhs. NG-PBRP-1, at 47-48 (Rev.); DPU 56-1). National Grid estimates that the value of one basis point in the rate year is approximately $222,299; the Company proposes to update this value annually (Exh. NG-PBRP-1, at 48 (Rev.)). The Company also proposes to earn the full amount of the incentive upon reaching the repair target of 100 leaks over the baseline of 425 leaks (Exh. NG-PBRP-1, at 47-48 (Rev.)). Further, if National Grid continues to repair non-environmentally significant Grade 3 leaks beyond that point (i.e., more than 525 leaks per year), then the Company proposes to accrue additional earnings on a pro-rata basis for each additional leak repaired (Exh. DPU 56-1).

The Company states that the benefits to customers from reducing the number of non-environmentally Grade 3 leaks on National Grid's distribution system include: (1) increased customer satisfaction and improved stakeholder relations by eliminating gas odors from non-hazardous leaks; (2) increased operating expense efficiency due to a reduction in repeat visits to investigate said odors; and (3) improved public safety by reducing the potential for Grade 3 leaks to become hazardous or environmentally significant (Exh. NG-PBRP-1, at 46-48 (Rev.)).

c. Non-Pipeline Alternative

The Company states that the non-pipeline alternative shared savings mechanism PIM is intended as a performance incentive to encourage the pursuit of alternatives to traditional gas infrastructure investments (Exh. NG-PBRP-1, at 43, 49 (Rev.)). The Company explains that these alternatives would generate customer benefits, but otherwise would be uneconomic for the Company to pursue (Exhs. NG-PBRP-1, at 49-50, 54 (Rev.); NG-PBRP-Rebuttal-1, at 11-12).

The Company defines a non-pipeline alternative as a solution or a portfolio of solutions consisting of demand-side resources, supply-side resources, or a combination of the two, that delays, reduces, or eliminates the need to invest in traditional gas pipeline infrastructure solutions (Exh. NG-PBRP-1, at 50 (Rev.)). For example, the Company states that potential non-pipeline alternatives include developing local renewable natural gas projects when a reinforcement project would otherwise be needed, building a shared geothermal loop instead of a main expansion, or deploying aggressive energy efficiency and demand response instead of building a new pipeline to meet demand (Exh. NG-PBRP-1, at 51 (Rev.)). National Grid explains that, absent the non-pipeline alternative shared savings mechanism, the Company would have a financial disincentive to pursue operating expense-driven non-pipeline methods to meet customer need when it would otherwise pursue a traditional gas pipeline solution (Exh. NG-PBRP-1, at 50 (Rev.)).

The Company proposes to collect a performance incentive equal to 30 percent of the net present value of the estimated net benefits generated by a non-pipeline alternative (Exh. NG-PBRP-1, at 56 (Rev.)). The Company will calculate the net benefits based on: (1) the cost savings of the non-pipeline alternative compared to the traditional infrastructure alternative; and (2) the societal cost of carbon[64] benefits over the useful life of the non-pipeline alternative (Exh. NG-PBRP-1, at 56 (Rev.)). The Company will exclude from this incentive calculation any cost savings generated during the term of the PBR (Exh. NG-PBRP-1, at 54-55 (Rev.)).

To select a non-pipeline alternative, the Company proposes a three-stage evaluation process during which it would: (1) identify areas of need that would be appropriate for a non-pipeline alternative and perform a competitive solicitation for proposals; (2) evaluate proposals internally to ensure feasibility; and (3) perform a benefit-cost analysis to determine

---

64 When natural gas is burned it emits carbon dioxide (CO_2), which is a greenhouse gas.

whether the benefits generated exceed the costs (Exh. NG-PBRP-1, at 52-53 (Rev.)). The Company will pursue a non-pipeline alternative only if the net present value of the cost of the non-pipeline alternative, including the incremental incentive collected by the Company, is lower than the cost of the traditional gas pipeline project (i.e., if the benefit-cost ratio is greater than one) (Exh. NG-PBRP-1, at 53, 56 (Rev.)). If multiple non-pipeline alternatives are identified to address a system need, the Company will select the non-pipeline alternative with the highest benefit-cost ratio after considering expected customer participation levels (Exh. NG-PBRP-1, at 53 (Rev.)).

2. Scorecard Metrics

a. Introduction

National Grid states that scorecard metrics are important for the Department's evaluation of the Company's performance under the PBR plan (Exh. NG-PBRP-1, at 62 (Rev.)). Unlike PIMs, the scorecard metrics under the Company's proposal do not include financial incentives for achievement of specified targets and, as such, will not have any bearing on the Company's revenue requirement. As noted above, the Company's proposes a total of eight scorecard metrics that fall into one of three general categories, as shown in the table below:

Performance Area	Scorecard Metric	Description
Safety & Reliability	Damage Prevention	The damage prevention metric includes five specific measures showing the total annual damage rate of the Company's gas distribution facilities by root cause.
	API 1173 Maturity Score	Performance against maturity score for each of the 10 elements in years 1, 3, and 5 per review conducted by 3rd party assessor.
Customer Satisfaction & Engagement	Web User Experience Index	1 to 100 score on a web-based survey that assesses the customer's experience with the Company's website in six areas: functionality, usability, intelligence, performance, engagement, and visual design.
	Customer Adoption of Digital Bill Pay	Number of successful digital channel payment transactions as a percentage of transactions across all engagement channels.
	First Contact Resolution	Percentage of customer issues that are resolved by a customer representative on the first contact.
	Average Speed of Answer	Average length of time it takes for a customer representative to answer a customer once they have exited the automated system.
	New Gas Customer Connections	Compares the Company's installation date for a new gas service to a customer's need date that is set with the customer requesting the new gas connection.
Emissions Reduction	Methane Emissions	Annual methane emissions associated with number of miles of pipe replaced by material type under the GSEP program from a CY 2019 baseline.

(Exh. NG-PBRP-1, at 62-63, Table 4 (Rev.)).

b. Safety and Reliability Metrics

The Company proposes two scorecard metrics under the safety and reliability category: (1) damage prevention metric; and (2) API 1173 maturity score metric (Exh. NG-PBRP-1, at 62 (Rev.)). The damage prevention metric tracks annual damage rates of the Company's gas distribution facilities by root cause and consists of five specific measures: (1) total number of damages per 1,000 tickets; (2) total number of at-fault damages per 1,000 tickets (Company at-fault); (3) total number of at-fault damages due to records per 1,000 tickets (Company at-fault); (4) total number of at-fault damages due to human error (miss mark by locator) per 1,000 tickets (Company at-fault); and (5) total number damages not-at-fault (third-party contractor) per 1,000 tickets (Exh. NG-PBRP-1, at 64 (Rev.)). National Grid proposes a baseline using Company data for the January 1, 2019 through December 31, 2019 time period, which the Company states is the most recent full year data available (Exh. NG-PBRP-1, at 64 (Rev.)).

The API 1173 maturity score metric measures the progress of the Company's Pipeline Safety Management System ("PSMS") based on the recommended practices of the API 1173 (Exhs. NG-PBRP-1, at 64 (Rev.); DPU 20-11, at 1).[65] The Company proposes to establish the baseline for this metric using an independent assessment performed in 2021 (Exhs. NG-PBRP-1, at 65 (Rev.); DPU 20-11, at 2). The independent assessor thereafter would evaluate the Company's progress every other year (Exh. NG-PBRP-1, at 65 (Rev.)).

c. Customer Satisfaction and Engagement Metrics

The Company proposes the following five metrics in the category of customer satisfaction and engagement: (1) a web user experience index metric that assesses customer experience with the Company's website; (2) a customer adoption of digital bill pay metric to

65 API 1173 sets forth a framework for energy pipeline operators to establish and implement a comprehensive safety management system. See https://inspectioneering.com/tag/api+rp+1173.

measure the percentage of customers who adopt digital bill payments; (3) a first contact resolution metric to measure the percentage of customer issues that are resolved by a customer representative on the first contact; (4) an average speed of answer metric to track the average length of time it takes for a customer representative to answer a customer after exiting the automated call system; and (5) a new gas customer connections metric to measure the fraction of new gas customer connections that are completed by the customer's need date (Exh. NG-PBRP-1, at 66-72 (Rev.)).

The web user experience index metric is based on a survey where the customer rates the Company's website in the areas of functionality, usability, intelligence, performance, engagement, and visual design (Exh. DPU 20-10, at 2). The customer rates these areas on a five-point scale, the results are combined and translated to a 1 to 100 score, and the scores for all surveyed customers are averaged to determine the total index score (Exh. DPU 20-10, at 2). The Company proposes to hire AnswerLab, a third-party vendor, to provide the tools and methodology used for this metric (Exh. NG-PBRP-1, at 67 (Rev.)). The Company proposes a baseline score of 47 out of 100, which was established using survey data from September 2019 to August 2020 (Exh. NG-PBRP-1, at 67 (Rev.)). The Company has a target score of 51 by the end of the PBR term in 2026 (Exh. DPU 20-10, at 2).

The customer adoption of bill pay metric tracks the percentage of customers who utilize digital channels (i.e., web, mobile, or the interactive voice response system) rather than non-digital to make payments (Exh. NG-PBRP-1, at 67-68 (Rev.)). The Company proposes a baseline of 18 percent, which was established using survey data from

September 2019 to August 2020 (Exh. NG-PBRP-1, at 68 (Rev.)). The Company has a target goal of 30 percent of payments from digital channels by the end of the PBR term (Exh. DPU 20-10, at 3).

The first contact resolution metric tracks the percentage of customer calls that are resolved by a single contact with the Company (Exh. NG-PBRP-1, at 68 (Rev.)). The data is compiled through an after-call survey that asks if (1) the call was the customer's first contact with National Grid on their issue and (2) the issue was resolved by the call (Exh. DPU 20-10, at 4). If the customer answers "yes" to both of these questions, the customer is included in the percentage of customers counted in the metric (Exh. DPU 20-10, at 3). The after-call survey was launched in January 2020, and the Company proposes to establish a baseline from a weighted average of monthly results over calendar year 2020 (Exh. NG-PBRP-1, at 69 (Rev.)). National Grid states that because 2020 was an atypical year due to the COVID-19 pandemic, the Company would establish a target goal after recording three full years of data (Exh. DPU 20-10, at 4).

The average speed of answer metric measures the average time that a customer waits after exiting the interactive voice response system in order to speak to a service representative (Exh. NG-PBRP-1, at 69 (Rev.)). The Company includes all types of calls in the metric (Exh. NG-PBRP-1, at 69 (Rev.)). The Company proposes a target goal of 123 seconds by the end of the PBR term, which is based on a weighted average of wait times from calendar year2017 through calendar year 2020 (Exh. DPU 20-10, at 4).

The new gas customer connections metric would compare the Company's installation date for a new gas service to a customer's "need date" that is set at the time that the customer requests the new gas connection to be operational (Exhs. NG-PBRP-1, at 70 (Rev.); DPU 20-10, at 4). A need date is met if the installation date of the new gas service is on, or before, the customer's need date (Exh. DPU 20-10, at 4). This data will be logged in the Company's Maximo Work Management system and the metric would be calculated by dividing the number of work orders that have met the need date by the total work orders in the system in the particular calendar year (Exh. DPU 20-10, at 4-5). The Company has not proposed a baseline or a target goal for the metric, as past performance data is not available (Exh. DPU 20-13). The Company proposed to begin collecting data in April 2021 and anticipates that the metric will act as a stimulus for continuous improvement (Exh. DPU 20-10, at 5).

d. Emissions Reduction Metric

The Company proposes a methane emissions scorecard metric under the emissions reduction category. The methane emissions metric would measure the Company's annual reduction in methane emissions resulting from the GSEP program (Exh. NG-PBRP-1, at 72 (Rev.)). The Company's goal for this metric is to meet the Department of Environmental Protection's annual declining methane emissions targets pursuant to 310 CMR 7.73 (Exh. DPU 20-10, at 5). The Company proposes a baseline of 114,828 metric tons of carbon dioxide equivalent emissions, which was established based on reported data from calendar year 2019 (Exh. NG-PBRP-1, at 73 (Rev.)).

C. Positions of the Parties

1. Attorney General

The Attorney General argues the Company's leak backlog reduction PIM should be rejected because it does not meet one of the Department's threshold principles for PIM design, namely activity must be clearly outside a distribution company's public service obligations (Attorney General Brief at 32-34, citing D.P.U. 18-150, at 121). The Attorney General asserts that the remediation of leaks on a utility's system is a core part of a distribution company's existing public service obligation (Attorney General Brief at 34). Further, the Attorney General contends that LDCs are required to provide service that is safe, economic, and reliable in exchange for a fair rate of return on its investments, and that the remediation of leaks is a vital part of that obligation (Attorney General Brief at 34). According to the Attorney General, however, National Grid's proposed leak reduction PIM, if approved, would provide the Company with an opportunity to receive an additional financial incentive—over and above just and reasonable compensation— to perform tasks that already are part of the regulatory compact (Attorney General Brief at 34).[66]

[66] In exchange for the grant of an exclusive right to provide utility service in a given service territory, regulators determine how much the utility is allowed to invest and in what, how much the utility can charge for service, and the profit margin of the utility, which is referred to as the "regulatory compact." In Re Binghampton Bridge, 70 U.S. 51, 74 (1865) ("if you will embark, with your time, money, and skill, in an enterprise which will accommodate the public necessities, we will grant to you, for a limited period or in perpetuity, privilege.")

The Attorney General also argues that the leak backlog reduction PIM design is flawed as there is no penalty attached to underperformance (Attorney General Brief at 34). The Attorney General asserts that without a penalty, the Company could reduce Grade 3 leak repair activities to improve earnings, which would represent a decrease in service quality over prior performance (Attorney General Brief at 34-35). Thus, the Attorney General maintains that the design of the leak backlog reduction PIM results in an asymmetric incentive that requires additional investment from ratepayers for good performance, but no consequence to the Company in the event of service quality deterioration (Attorney General Brief at 34-35).

Further, the Attorney General argues that the Department should expand its existing regulatory framework set forth in 220 CMR 114.00 to impose additional service quality standards to accelerate the repair of Grade 3 leaks (Attorney General Brief at 35-36). As an example, the Attorney General refers to the establishment of service quality standards such as the remediation of poorly performing electrical circuits to suggest that service quality metrics within the PBR could be designed to accelerate the remediation of Grade 3 leaks (Attorney General Brief at 36, citing Service Quality Guidelines, D.T.E. 99-84 (2000); Service Quality Guidelines, D.T.E. 04-116-C, at 8 (2007).

Regarding the Company's proposed non-pipeline alternatives PIM, the Attorney General argues that the Department should reject the proposal and defer its consideration to the ongoing investigation in docket D.P.U. 20-80 (Attorney General Brief at 37). The Attorney General generally supports the consideration of non-pipeline alternatives for all gas companies' capital planning process but argues that the Company's proposed non-pipeline alternative incentive fails to meet the Department's traditional design guidelines for PIMs (Attorney General Brief at 37, 39).

In particular, the Attorney General maintains that the Company's proposed non-pipeline alternative is too loosely defined to meet the Department's evaluation criteria (Attorney General Brief at 38, citing Exh. NG-PBR-1, at 50 (Rev.)). Further, the Attorney General argues that the Company's proposed internal evaluation process to decide which non-pipeline alternative to pursue is open-ended and does not have a clearly defined scope, timeline, or cost-benefit analysis methodology (Attorney General Brief at 38, citing Exh. NG-PBR-1, at 52-53 (Rev.); Tr. 7, at 771, 773, 774). Finally, the Attorney General contends that National Grid's proposal creates perverse incentives for the Company, as it would allow the Company to retain 30 percent of the present value of determined net benefits for all non-pipeline alternatives pursued regardless of the benefits and costs associated with the activities (Attorney General Brief at 39). Based on these considerations, the Attorney General concludes that, as proposed, National Grid's non-pipeline alternative incentive mechanism will allow the Company to collect significant incentives from ratepayers through an ill-defined selection process without adequate accountability to ratepayers (Attorney General Brief at 38-39).

The Attorney General did not address the Company's proposed scorecard metrics on brief.

2. DOER

DOER recommends that the Company's proposed non-pipeline alternative framework should be examined as part of the Department's investigation in docket D.P.U. 20-80 to help achieve consistency across LDCs (DOER Brief at 7-8). Alternatively, DOER proposes several design modifications to the Company's proposed non-pipeline alternative PIM to lower costs to ratepayers and to ensure greater consistency with the Commonwealth's GHG emissions reduction efforts (DOER Brief at 7). The proposed modifications include the following: (1) removing the social cost of carbon benefits from the Company's incentive[67]; (2) requiring a cap on the level of incentives for each non-pipeline alternative; (3) prioritizing non-pipeline alternatives that maximize GHG emissions reductions; (4) requiring a timeline for transitioning the customers served by fossil-fuel, non-pipeline alternatives to a net-zero solution within 30 years; and (5) deploying cost-effective geothermal shared loops as non-pipeline alternatives for main replacements serving existing customers (DOER Brief at 6-10, 13-15; DOER Reply Brief at 2-3).

DOER also recommends that the Department direct the Company to propose a modified Total Resource Cost[68] ("TRC") test inclusive of targeted energy efficiency with

---

67 DOER does not oppose including the social cost of carbon in evaluating the costs and benefits of a non-pipeline alternative proposal (DOER Brief at 15).

68 The Green Communities Act requires the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply. G.L. c. 25 §§ 21(a), 21(b)(1). As part its energy efficiency plan reviews, the Department employs the TRC test to determine cost-effectiveness in each Program Administrator's Three-Year Plan, which includes all benefits and costs associated with the energy system, as well as all benefits and costs associated with program

localized benefits (e.g., the value of avoided distribution infrastructure) in its energy efficiency plan ("Three-Year Plan") prior to considering incremental energy efficiency as a non-pipeline alternative (DOER Brief at 13; DOER Reply Brief at 3-4). DOER posits that offerings inclusive of localized benefits, such as demand response or incremental energy efficiency, may be cost-effective under a modified TRC test; consequently, these offerings should be evaluated in the Company's Three-Year Plan rather than as part of a non-pipeline alternative portfolio (DOER Brief at 10, 12-13; DOER Reply Brief at 3-4). Finally, DOER argues that Company should be required to consult with (1) DOER when commencing and selecting non-pipeline alternative solicitations, and (2) the Energy Efficiency Advisory Council when developing a modified TRC test inclusive of localized benefits (DOER Brief at 9-10, 13).

DOER did not address the Company's proposed leak backlog reduction PIM or the proposed scorecard metrics on brief.

3. TEC

TEC argues that the Department should reject the Company's proposed leak backlog reduction PIM (TEC Brief at 11; TEC Reply Brief at 6). Similar to the Attorney General, TEC contends that the maintenance of system integrity and safety does not fall outside of the Company's public service obligations and, therefore, the proposed leak backlog reduction

participants. Energy Efficiency Guidelines, D.P.U. 20-150-A, App. A, § 3.4.3 (2021); 2019-2021 Three-Year Energy Efficiency Plans Order, D.P.U. 18-110 through D.P.U. 18-119, at 61 (2019).

PIM does not meet the Department established PIM criteria (TEC Brief at 11, citing D.P.U. 18-150). Further, regarding National Grid's backlog of Grade 2 leaks, TEC argues that the Company's proposed incentive amount could result in the misdirection of resources and attention toward the repair of Grade 3 leaks from the remediation of the more pressing Grade 1 and Grade 2 leak repairs (TEC Brief at 11, citing Exh. NG-PBRP-Rebuttal-1, at 8). TEC supports the Attorney General's other arguments against the proposed leak reduction PIM, except for expanded service quality criteria and penalties (TEC Reply Brief at 7).

Further, TEC rejects any notion that recent legislation providing that the Department "may level a penalty" related to a company's leak reduction efforts justifies the preemptive establishment of a symmetrical upside incentive to counteract the risk of these penalties (TEC Reply Brief at 6-7, citing Company Brief at 72; Climate Act, § 87). TEC contends that any leak remediation targets or goals that the Climate Act may require are unknown as of this time, and that any concern about penalties are premature and speculative (TEC Reply Brief at 7).

Regarding the Company's proposed non-pipeline alternative PIM, TEC argues that the proposal should be rejected because its net-present value formula underestimates the risk borne by ratepayers and would be better suited for review in a broader investigation, such as in docket D.P.U. 20-80 (TEC Brief at 12; TEC Reply Brief at 8-9). TEC contends that the use of the Company's weighted average cost of capital ("WACC") to discount costs and benefits of a non-pipeline alternative proposal fails to capture the higher risk nature of unfamiliar technologies and business models and may involve the expansion of services outside the Company's business as a gas utility (TEC Reply Brief at 7-8).

TEC supports the Attorney General's argument that ratepayers will compensate Company shareholders for failed non-pipeline alternative projects if projected benefits do not arrive as forecasted (TEC Reply Brief at 8). Further, TEC agrees with DOER that social cost of carbon benefits should be excluded from any non-pipeline alternative incentive calculation and argues that the benefit of avoided emissions accrue globally and are not actual costs avoided by the Company's ratepayers (TEC Reply Brief at 7-8). Finally, TEC argues that if the Company's proposed non-pipeline alternative PIM is approved, it is unreasonable to expect that intervenors participate in "multiple one-off proceedings" tied to a base distribution rate case due to cost and time constraints (TEC Reply Brief at 8-9). Thus, according to TEC, it is essential that the Department promote non-pipeline alternatives that are administratively efficient and within the scope of expertise of the utility (TEC Reply Brief at 9). In this regard, TEC asserts that a carefully designed non-pipeline alternative framework could have been proposed by the Company and approved in this proceeding, but, instead, National Grid offered an unfocused and ambiguous proposal that involves a novel compensation mechanism to enter business ventures and utilize technologies where the Company has no experience (TEC Reply Brief at 9).

TEC did not address the Company's proposed scorecard metrics on brief.

4. Company

a. PIMs

i. Leak Backlog Reduction PIM

National Grid argues that its proposed leak reduction backlog PIM meets the first threshold of the Department's two-prong test relative to PIMs, as the PIM is designed to encourage elimination of non-hazardous Grade 3 leaks that are in addition to required compliance work (Company Brief at 41, citing Exhs. NG-PBRP-1, at 45, 48 (Rev.); AG 3-13). The Company contends that closing out of Grade 3 leaks improves public safety because it eliminates the possibility that the Grade 3 leak can become a hazardous leak (i.e., a Grade 2 or Grade 1 leak) (Company Brief at 41). Further, the Company claims that eliminating these leaks will reduce costs associated with repeat site visits for odor complaints (Company Brief at 41-42).

National Grid also argues that its proposed leak backlog reduction PIM meets the second threshold of the Department's two-prong test, as the PIM is designed to best achieve the Commonwealth's energy goals (Company Brief at 42, citing Exh. NG-PBRP-1, at 48 (Rev.)). According to the Company, the proposed PIM will encourage elimination of the leak backlog once all compliance is completed, which creates quantifiable benefits in the reduction of repeat calls to the Grade 3 leak location for investigation of odors and the elimination of annual surveillance activities, and even greater qualitative benefits including customer satisfaction and improved relationships with communities and stakeholders (Company Brief at 42). The Company also asserts that the proposed PIM creates no perverse incentives and there is no double counting through other mechanisms, such as the GSEP mechanism (Company Brief at 42).

The Company disagrees with the Attorney General and TEC's arguments that the proposed PIM rewards the Company for tasks that it already is obligated to perform (Company Brief at 71-72). The Company argues that the proposed leak backlog reduction PIM meets the Department's threshold requirements for a PIM because it encourages superior performance over the Company's required performance (Company Brief at 71). In particular, the Company notes there is no required timeline for the repair of non-environmentally significant Grade 3 leaks discovered before January 1, 2018 (Company Brief at 40). Therefore, the Company maintains that the remediation of Grade 3 leaks at a pace higher than established in the test year is a task that is outside of the Company's core service obligations as an LDC (Company Brief at 72).

Further, the Company disagrees with the Attorney General's argument that the Department should expand the service quality framework to include measures that would accelerate the repair of Grade 3 leaks (Company Brief at 72). The Company argues that the imposition of a penalty for underperformance in leak remediation would discourage the Company from reaching the PIM target if leak repair costs were to exceed penalties (Company Brief at 72). Moreover, National Grid notes that the cost of remediating 200 more Grade 3 leaks is estimated at $784,400, an amount that will not be recovered through base distribution rates and which far exceeds the PIM value, which the Company calculates at $222,299 (Company Brief at 72, citing Exhs. NG-PBRP-Rebuttal-1, at 5-7; DPU 42-9; Tr. 7, at 831-832).

National Grid also argues that the proposed leak backlog reduction PIM creates a symmetrical performance metric, as the Climate Act allows the Department to develop a penalty mechanism associated with failure to meet leak remediation targets (Company Brief at 72-73, citing Climate Act, § 87). In this regard, National Grid disagrees with TEC's assertion that the Company's concern over potential penalty mechanisms included in the Climate Act is speculative and premature (Company Brief at 81). Rather, the Company contends that TEC has misunderstood the legislation, as the only remaining classification of leaks for which there is no established remediation timeline is non-environmentally significant Grade 3 leaks; therefore, the Company asserts that the new interim target requirement will apply only to these leaks (Company Brief at 81). The Company further states that the Department's approval of new leak remediation targets will set a level of Grade 3 leak repair that would now be part of an LDC's core obligations, so that acceleration of Grade 3 leak repairs above this level, as proposed in the leak reduction PIM, would be outside of the Company's core service obligations (Company Brief at 82).

Finally, National Grid disagrees with TEC's argument that the proposed leak reduction PIM will cause the Company to misdirect attention and resources away from Grade 2 leaks to focus on Grade 3 leaks (Company Brief at 81). National Grid asserts that since it is required by law to eliminate Grade 2 leaks within twelve months of discovery, the

Company will not be able to misallocate resources in this manner and it will continue to prioritize Grade 2 leaks over Grade 3 leaks (Company Brief at 81).

ii. Non-Pipeline Alternatives PIM

The Company argues that its non-pipeline alternative PIM satisfies the Department's two-prong threshold test for incentive mechanisms (Company Brief at 43, citing Exhs. AG 3-13; AG 3-14). First, the Company contends that its proposed PIM supports the Commonwealth's GHG emissions reduction goals and falls outside of the Company's public service obligation to provide safe, low-cost, and reliable service to customers while satisfying service quality expectations (Company Brief at 43-44). Second, the Company argues that its proposal satisfies the Department's design test for incentive mechanisms because: (1) non-pipeline alternatives aim to serve both existing and future load with cost-effective alternatives to traditional gas supply, transmission system, and distribution system; (2) the Company will play a clear and distinct role in bringing the desired outcome by evaluating, selecting, and implementing non-pipeline alternatives; (3) a cost-benefit analysis will demonstrate that the net-present value of the proposed PIM benefits justifies the costs; (4) the concept of a shared-savings mechanism is consistent across all electric and gas companies to encourage investment in non-wires or non-pipeline alternatives; and (5) the proposed PIM does not create perverse incentives (Company Brief at 44-45).

National Grid disagrees with intervenors' assertions that the consideration of the non-pipeline alternative PIM should be deferred to another proceeding, and the Company maintains that the PIM's approval does not preclude the Department from issuing guidance for the development and implementation of non-pipeline alternatives in docket D.P.U. 20-80 (Company Brief at 73-74, 77). According to National Grid, its proposal anticipates seeking Departmental approval prior to implementing any non-pipeline alternative, and the Company's experience with the non-pipeline alternative PIM could help inform the broader proposals to be considered in docket D.P.U. 20-80 (Company Brief at 74, 82).

In response to the Attorney General's and TEC's arguments that the proposed non-pipeline alternative projects are ill-defined and open-ended, the Company asserts that it has defined and provided several examples of supply- and demand-side resources that could contribute to non-pipeline alternatives (Company Brief at 74-75). Further, the Company maintains that benefits would materialize for ratepayers because only non-pipeline alternatives that meet system reliability needs with cost savings would be pursued, and that evaluating the net present values of benefits ensures that the bulk of the benefits accrue to ratepayers during the first few years of a non-pipeline alternative (Company Brief at 75, 77; Company Reply Brief at 27).

In general, the Company also disagrees with the design modifications proposed by DOER and maintains that it is appropriate to include a social cost of carbon benefit in its incentive calculation without a cap on the level of incentives (Company Brief at 80). The Company disagrees that non-pipeline alternatives should be selected to maximize GHG emissions reductions and argues that maximizing costs savings allows for all costs and benefits of a non-pipeline alternative to be considered in its analysis, which would maximize net benefits to customers (Company Brief at 78). Although supportive of geothermal shared loops as an illustrative example of a non-pipeline alternative, the Company argues that its decision to pursue geothermal as an alternative to planned gas main replacement and extension depends on the approval and insights from its geothermal demonstration project currently before the Department in docket D.P.U. 21-24 (Company Brief at 79). Further, the Company argues that formal coordination with DOER prior to selecting a non-pipeline alternatives would be unnecessary and inefficient (Company Brief at 78-80). Finally, National Grid argues that the instant proceeding is an inappropriate venue to discuss DOER's recommendation that the Company should include infrastructure avoidance benefits in the TRC, and that this recommendation should not preclude approval of the proposed non-pipeline alternative PIM (Company Brief at 79; Company Reply Brief at 24-25).

National Grid also disagrees with TEC's contention that employing the Company's WACC undervalues the risk of non-pipeline alternatives (Company Reply Brief at 28). National Grid asserts that non-pipeline alternatives are expected to be proven technologies and using the WACC discount rate is consistent with the Company's other capital project evaluations (Company Reply Brief at 28). Finally, the Company asserts that it does not expect presenting more than a few non-pipeline alternatives that already would have resulted in positive benefit-cost analysis, and that any participation in further non-pipeline alternative proceedings is not expected to be burdensome for interested parties (Company Reply Brief at 28).

b. Scorecard Metrics

i. Introduction

National Grid argues that its proposed suite of scorecard metrics is a critical aspect of the PBR framework and will allow the Department to monitor the Company's progress during the term of the PBR (Company Brief at 45). The Company has proposed eight metrics that can be classified as either: (1) safety and reliability; (2) customer satisfaction and engagement; or (3) emissions reduction (Company Brief at 45).

ii. Safety and Reliability Metrics

The Company maintains that damages to its distribution infrastructure are a significant risk factor in the occurrence of major incidents in the Company's operating area (Company Brief at 45-46). Therefore, the Company contends that the damage prevention metric encourages a focus on the mitigation of important risk factors, and that reducing the likelihood of damages will reduce risk to employees, customers, and communities (Company Brief at 46).

National Grid contends that the API 1173 maturity score metric will measure the implementation of the Company's PSMS and is intended to improve operational and managerial functioning and reduce the risk of pipeline safety incidents (Company Brief at 46). The Company claims that the API 1173 provides a structured and formal approach toward continued improvement in these areas (Company Brief at 46-47).

iii. Customer Satisfaction and Engagement Metrics

The Company argues that its web user experience index metric will benefit customers by providing National Grid with information about the quality of a customer's experience with the Company website (Company Brief at 47). Additionally, National Grid contends that its proposed customer adoption of bill pay metric will aid the Company in further developing its digital presence by improving self-service options (Company Brief at 48). According to the Company, customers value digital channels of bill pay and increasing customer adoption of these methods will meet customer expectations and increase efficiency by removing the need for the Company to process bill payments manually (Company Brief at 48).

In addition to its digital experience, the Company also aims to improve service on its customer help line through the proposed first contact resolution and average speed of answer metrics (Company Brief at 48-49). National Grid claims that resolving an issue with a single instance of customer contact with the Company has a large positive impact on customer satisfaction (Company Brief at 48). Further, the Company contends that it can use the information derived from these interactions to identify issues that cannot be remediated through a single contact and then initiate internal changes to improve future customer experiences (Company Brief at 48). Additionally, the Company will use the data from the average speed of answer metric claiming to lower customer wait times by improving self-service channels and contact center performance (Company Brief at 49).

Finally, the Company argues that its new gas customer connections metric provides benefits to ratepayers in the form of improved customer satisfaction and will encourage continuous improvement for the Company's process (Company Brief at 50). National Grid asserts that improving the proportion of customer need dates met will allow customers to better plan for and rely upon a prompt start to the delivery of the Company's gas services (Company Brief at 50).

iv. Emissions Reduction Metric

The Company's methane emissions metric is intended to measure the Company's annual methane emissions reductions associated with the number of miles and the material category of the leak-prone pipe replaced in its GSEP program (Company Brief at 50-51). The Company asserts that this scorecard metric measures one of the key recommendations from the Dynamic Risk Report[69] regarding pipeline safety (Company Brief at 50).

D. Analysis and Findings

1. PIMs

a. Review Criteria

The Department reviews PIMs based on the criteria established in D.P.U. 18-150. First, the Department must determine whether the PIM satisfies the threshold principles designed to weigh whether an action addressed in the PIM is appropriate to consider for performance incentives. D.P.U. 18-150, at 120. In making this determination, the

69 On January 29, 2020, Dynamic Risk Assessment Systems, Inc. released its Statewide Assessment of Gas Pipeline Safety Final Report (Exh. NG-GSC-2). The Dynamic Risk Report evaluates the physical integrity and safety of the Commonwealth's gas distribution systems operated by the seven investor-owned gas distribution companies and four municipal gas companies in the Commonwealth of Massachusetts, and the operations and maintenance policies, practices, and execution by these gas companies (Exhs. NG-GSC-1, at 15; NG-GSC-2).

Department has found that performance incentives can serve as a useful regulatory mechanism when used to positively influence distribution company behavior in the advancement of important public policy goals that are not directly aligned with a distribution company's public service obligations. Net Metering, SMART Provision, and the Forward Capacity Market, D.P.U. 17-146-B at 15-16, 56-59 (2019); see also D.P.U. 94-158, at 54 (an incentive plan should improve on a company's performance that would have been offered under current regulation). Conversely, performance incentives are generally not appropriate where the affected activity is within the distribution company's public service obligations. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 55-60 (2009); see also Western Massachusetts Electric Company, D.T.E. 04-40/D.T.E. 04-109/D.T.E. 05-10, at 5-6 (2006) (the type of expenditures recorded in the ordinary course of business and recovered as part of a company's test-year operations and maintenance expense should not be afforded special ratemaking treatment). The Department has found that to be considered on its design merits, a PIM first must be found to meet the threshold principles that: (1) it advances specific public policy goals; and (2) the affected activity is clearly outside a distribution company's public service obligations. D.P.U. 18-150, at 121.

Upon determining that a PIM meets these threshold principles, the Department must determine whether the proposed PIM meets appropriate design guidelines. The Department has determined that an appropriately designed incentive mechanism must: (1) be designed to encourage program performance that best achieves the Commonwealth's energy goals; (2) be designed to enable a comparison of (i) clearly defined goals and activities that can be sufficiently monitored, quantified, and verified after the fact, to (ii) the cost of achieving the target to the potential quantifiable benefits; (3) be available only for activities where the distribution company plays a distinct and clear role in bringing about the desired outcome; (4) be consistent across all electric and gas distribution companies, where possible, with deviations across companies clearly justified; (5) be created to avoid perverse incentives; and (6) ensure that the distribution company is not rewarded for the same action through another mechanism. D.P.U. 18-150, at 121-122, citing D.P.U. 17-13, at 42-43, 46; Investigation into Updating Energy Efficiency Guidelines, D.P.U. 08-50-A at 49-50 (2009); D.P.U. 94-158, at 52-66. In addition, the Department may allow a modification to an approved incentive mechanism where justified. D.P.U. 08-50-A at 49-50.

b. Leak Backlog Reduction

National Grid's proposed leak backlog reduction PIM is designed to award the Company a financial incentive if it reaches a certain threshold of remediated Grade 3 non-environmentally significant leaks, and to earn more financial incentive on a pro-rata basis for each additional leak repaired after reaching this threshold (Exhs. NG-PBRP-1, at 47 (Rev.); DPU 56-1). As discussed above, the Company argues that the proposed PIM satisfies the threshold principles designed to weigh whether an action addressed in the PIM is appropriate to consider for performance incentives (Company Brief at 41-42, 71-73, 81-82).

As an initial matter, we recognize that Grade 3 leak repairs can improve public safety by reducing the potential for such leaks to become hazardous or environmentally significant

(RR-DPU-35). Further, such repairs can enhance customer satisfaction and improved stakeholder relations by eliminating gas odors from non-hazardous leaks, as well as reduce operating expenses associated with repeat visits to investigate said odors (Exh. NG-PBRP-1, at 46-48 (Rev.)). The Department, however, is not persuaded that National Grid's proposed PIM measures activities outside of the Company's service obligation. As part of their public service obligation, utilities are responsible for providing safe, reliable, and least-cost service to customers. Massachusetts-American Water Company, D.P.U. 95-118, at 47 (1996); D.P.U. 94-158, at 3 (since it was established in 1919, the goal of the Department has been to ensure that the public utility companies that it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); The Berkshire Gas Company, D.P.U. 92-210, at 32 (1993). In fulfilling this obligation, the Department expects companies to satisfy basic service responsibilities in the course of their day-to-day business operations.

The maintenance of system safety and integrity, and therefore the activity of leak remediation, is substantially encompassed within the Company's public service obligation. The Company maintains that the absence of a defined timeline for Grade 3 leak remediation means that accelerating the repair of these leaks is outside of its service obligation (Exh. NG-PBRP-1, at 48 (Rev.); Company Brief at 40, 71-72). We disagree. Reducing Grade 3 leaks is an important service responsibility, and the potential for National Grid to accelerate this work does not change the fact that the Company must undertake these leak repairs in the day-to-day course of its operations in satisfaction of safety and reliability obligations.[70] In fact, because there is a backlog of Grade 3 leaks, it would seem a reasonable business practice to accelerate the repairs, regardless of any incentive to do so.[71] Thus, we are not persuaded that it is appropriate to approve a financial incentive that enables the Company to earn more than a fair financial return for tasks that it already is obligated to perform. Based on these considerations, we find that the proposed leak backlog reduction PIM does not satisfy the Department's threshold principle that the subject activity (i.e., Grade 3 leak repairs) is clearly outside a distribution company's public service obligations. D.P.U. 18-150, at 121.

Although our evaluation of the proposed leak backlog reduction PIM could end here, we find it necessary to comment on two other aspects of the proposal. First, we find that the lack of a penalty for the decline in Grade 3 non-environmentally significant leak repairs may result in an asymmetric incentive that requires additional investment from ratepayers for good performance, but no consequence to the Company in the event of service quality deterioration (Exh. DPU 42-7; Tr. 7, at 833-835). Next, we have concerns that the claimed benefits associated with this PIM would not be sufficiently quantified (e.g., the benefits associated with an unknown emission rate), thereby preventing a relevant determination of whether the amount of the incentive is reasonable (Exhs. NG-PBRP-1, at 49 (Rev.); DPU 20-9; Tr. 7,

70 Reducing gas leaks can reduce O&M costs over time, thereby supporting the obligation of providing least-cost service.

71 These reasonable business practices do not account for the obvious additional environmental benefits associated with reducing grade 3 leaks.

at 837-838; RR-DPU-35). Assuming that the Company's proposed leak backlog reduction PIM satisfied the threshold requirements, the Department still would have denied the proposal based on these deficiencies.

Based on the foregoing considerations and findings, the Department denies the Company's proposal to establish a leak backlog reduction PIM. However, given the importance of reducing the number of leaks on its system, the Department directs the Company to track both the current Grade 3 leak backlog and the Company's progress in reducing the number of outstanding Grade 3 leaks. National Grid shall report the results of tracking the Grade 3 leak backlog and its progress at reducing the number of outstanding Grade 3 leaks in the Company's annual PBR filings, beginning on June 15, 2023 (Exh. NG-PBRP-1, at 35 (Rev.)).

c. Non-Pipeline Alternative

The Company states that its non-pipeline alternative PIM is designed to encourage the pursuit of sustainable, cost-effective alternatives to traditional gas infrastructure investments to serve both existing and future gas customers (Exh. NG-PBRP-1, at 43, 49 (Rev.)). Further, the Company maintains that non-pipeline alternatives will create value for customers that would otherwise be uneconomic for the Company during the PBR term (Exhs. NG-PBRP-1, at 50 (Rev.); NG-PBRP-Rebuttal-1, at 11-12).

As noted above, as part of their public service obligation, utilities are responsible for providing safe, reliable, and least-cost service to customers. D.P.U. 95-118, at 47;

D.P.U. 94-158, at 3; D.P.U. 92-210, at 32.[72] Additionally, pursuant to G.L. c. 164, § 92, a gas company has an obligation to provide service to customers in a non-discriminatory manner and subject to reasonable terms and conditions. See Weld v. Gas and Electric Light Commissioners, 197 Mass. 556, 557 (1908) (it is the duty of a utility to exercise its monopoly franchise for the benefit of the public, with a reasonable regard for the rights of individuals who desire to be served, and without discrimination between them).

The Department has found that the obligation to serve a new, prospective gas customer is conditioned on: (1) the gas company's having sufficient physical capacity to do so without reducing service to existing customers; and (2) the prospective customer's paying the cost for installing suitable gas distribution facilities for service, so that existing customers do not subsidize the cost of the extension of service. Arnold/Hawkins v. Boston Gas Company, D.P.U. 93-AD-16, at 9 (1994); Boston Gas Company, D.P.U. 88-67 (Phase I) at 372 (1988); Riverdale Mills Corporation, D.P.U. 85-130, at 12 (1985). The Company is obligated to serve its existing customers in this manner as part of its public service obligation, and not future customers. The Company's non-pipeline alternative proposal, however, would provide an incentive for acquiring future customer (Exhs. NG-PBRP-1, at 50 (Rev.); DPU 23-9).

---

72 A fundamental difference between electric and gas companies is that substitutes for gas are readily available (e.g., propane, oil, and electricity), while electric service is an essential service for which no ready substitute exists. Boston Gas Company, D.P.U. 89-180, at 13-14 (1990), citing Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988).

In opening docket D.P.U. 20-80, the Department initiated a process for exploring strategies to enable the Commonwealth to achieve its 2050 climate goals. D.P.U. 20-80, Vote and Order Opening Investigation at 1. Specifically, the Department will explore strategies to enable the Commonwealth to move into its net-zero GHG emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; establishing new policies and structures that would protect ratepayers as the Commonwealth reduces its reliance on natural gas; examining the LDCs' role in the Commonwealth's achievement of its target 2050 climate goals; and potentially recasting the role of LDCs in the Commonwealth. D.P.U. 20-80, Vote and Open Opening Investigation at 1. Accordingly, the Department directed LDCs to issue a joint request for proposals for an independent consultant to conduct LDC-specific studies and prepare a collective report analyzing the feasibility of pathways for helping the Commonwealth achieve its climate goals. D.P.U. 20-80, Vote and Open Opening Investigation at 4-6. The Department is mindful that non-pipeline alternatives, incentives, and PBR plans may play a role in achieving these public policy goals alongside the pathways identified in docket D.P.U. 20-80.

The obligation of LDCs to meet specific public policy goals will be analyzed further in D.P.U. 20-80. As such, and given that the Company proposes to collect an incentive for acquiring new gas customers, the Department finds it is more appropriate to defer consideration of the Company's proposal to the proceeding in D.P.U. 20-80. In that proceeding, the Department and all interested parties can evaluate how LDCs can best administer a non-pipeline alternative. Accordingly, the Department denies the Company's proposal to establish a non-pipeline alternative PIM.

2. Scorecard Metrics

a. Introduction

As discussed in Section IV.D above, the Department has approved a PBR plan with a five-year term. In order to measure the full range of benefits that will accrue under the PBR plan, the Department finds that it is appropriate to establish a set of broad performance metrics that are tied to the goals of the PBR plan and that are consistent with the Department's regulatory objectives.

b. Safety and Reliability Metrics

As described above, the Company proposes two metrics in the category of safety and reliability. First is the damage prevention metric, under which the Company proposes the following five specific measures: (1) total number of damages per 1,000 tickets; (2) total number of at-fault damages per 1,000 tickets (Company at-fault); (3) total number of at-fault damages due to records per 1,000 tickets (Company at-fault); (4) total number of at-fault damages due to human error (miss mark by locator) per 1,000 tickets (Company at-fault); and (5) total number damages not-at-fault (third-party contractor) per 1,000 tickets (Exh. NG-PBRP-1, at 64 (Rev.)). The Department finds that the damage prevention metric appropriately creates a focus on risk mitigation and safety (Exh. NG-PBRP-1, at 64 (Rev.)). The Department, however, directs the Company to expand the damage prevention metric to include the following additional measures: (1) cost of at-fault damages (Company at-fault);

(2) cost of not-at-fault damages (third-party contractor); and (3) costs recovered for not-at-fault damages (third-party contractor). These additional measures will allow the Department to better assess the impacts of damages that are deemed the Company's fault versus those where the Company is deemed not at fault. Further, the Department directs the Company to provide in its annual PBR compliance filing the most recent three years of data of the aforementioned additional measures in order to establish an appropriate benchmark.

The second metric in the category of safety and reliability is the API 1173 maturity score metric. The Company proposes to have an independent third-party assessor review its progress on the implementation of its PSMS, with the establishment of a baseline in fiscal year 2021 and an evaluation of the Company's progress to occur thereafter every other year (Exh. NG-PBRP-1, at 65 (Rev.)). The Department finds that the Company's commitment to the improvement of its PSMS will result in improvements in safety and reliability, and, ultimately, in ratepayer benefits.

Based on the above considerations, the Department finds that the proposed scorecard metrics appropriately track the Company's progress and performance to improve in the important areas of safety and reliability over the term of the PBR plan. Accordingly, the Department approves the damage prevention metric, as modified above, and the API 1173 maturity score metric, as proposed. The Company shall report on these metrics in its annual PBR filings, beginning on June 15, 2023 (Exh. NG-PBRP-1, at 35 (Rev.)).

c. Customer Satisfaction and Engagement Metric

As described above, the Company proposes five scorecard metrics related to customer satisfaction and engagement. The Department finds that measurements and improvements in customer satisfaction are important and there is value in such metrics as part of a PBR plan evaluation. With the exception of the new gas customer connections metric, the Department finds that these metrics, as proposed, would measure the progress that the Company makes to improve customer satisfaction and engagement over the term of the PBR plan. Accordingly, the Department approves the web-user experience index, the customer adoption of digital bill pay, the first contact resolution, and the average speed of answer metrics. The Company shall report on these metrics in its annual PBR filings, beginning on June 15, 2023 (Exh. NG-PBRP-1, at 35 (Rev.)).

The new gas customer connections metric is designed to compare the Company's installation date for a new gas service to a customer's need date that is set at the time that the customer requests that the new gas connection to be operational (Exh. NG-PBRP-1, at 70 (Rev.)). In light of the Climate Act and the Massachusetts 2050 Decarbonization Roadmap,[73] the Department finds that it is not appropriate to approve a metric that encourages new customer natural gas connections at a time when the Commonwealth is considering achieving emission reductions in the building sector through electrification of space heating. Further, as noted above, the Department is considering the future of natural gas, including strategies

---

73 See https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

to enable the Commonwealth to move into its net-zero GHG emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; establishing new policies and structures that would protect ratepayers as the Commonwealth reduces its reliance on natural gas; examining the LDCs' role in the Commonwealth's achievement of its target 2050 climate goals; and potentially recasting the role of LDCs in the Commonwealth. D.P.U. 20-80, Vote and Order Opening Investigation at 1-3. Accordingly, the Department does not approve the Company's proposed new gas customer connections metric.

d. Emissions Reductions

The Company proposes one metric related to emissions reductions, the methane emissions metric. The methane emissions metric would measure the Company's annual reduction in methane emissions resulting from the GSEP program (Exh. NG-PBRP-1, at 72 (Rev.)). The Department finds that this metric will provide assurance that the Company continues to properly manage its GSEP program and continuously achieves the annually declining emissions target goals per the Department of Environmental Protection's regulations at 310 C.M.R. 7.73. Therefore, the Department approves the methane emissions metric as proposed by the Company.

Additionally, the Department directs the Company to develop a second emissions reduction scorecard metric. This metric shall track the Company's commitment to engaging relevant stakeholders over the term of PBR in conversations about the role of the natural gas industry in achieving the Commonwealth's goals of reducing GHG emissions to net zero by

2050 and by 45 percent below the 1990 level by 2030. Secretary of the Executive Office of Energy and Environmental Affairs' Determination of Statewide Emission Limit for 2030 at 4.[74] While the Department will review specific proposals from the Company in D.P.U. 20-80, the Department finds that such a metric would be useful as the Commonwealth develops policies to achieve the mandates of the Climate Act. The Department directs the Company to provide this scorecard metric as part of its first PBR Compliance filing. The Company shall report on the methane emissions metric and the new stakeholder engagement metric in its annual PBR filings, beginning on June 15, 2023 (Exh. NG-PBRP-1, at 35 (Rev.)).

VI. RATE BASE

A. Introduction

As of March 31, 2020, National Grid booked a test-year-end rate base of $3,406,844,914 (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 3)). From this amount, the Company proposed to subtract $367,556,726 in normalizing adjustments and $19,853,506 in known and measurable adjustments for a total proposed rate base of $3,019,434,682 (Exhs. NG-AS-1, at 3; NG-RRP-2, Sch. 11, at 1 (Rev. 3)). National Grid's total proposed rate base consists of: (1) $6,483,805,458 in total utility plant in service; (2) $15,938,471 in materials and supplies; (3) $5,402,311 in heel gas inventory; and (4) $61,759,030 in cash working capital; less (5) $3,547,470,588 in deductions, such as construction work in progress ("CWIP"),

---

74 See https://www.mass.gov/doc/2030-ghg-emissions-limit-letter-of-determination/download.

plant held for future use, contributions in aid of construction ("CIAC"), accumulated amortization and depreciation, accumulated deferred income tax ("ADIT"), and customer deposits (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 3)).

B. Plant Additions

1. Introduction

From January 1, 2017, through March 31, 2020, the Company invested a total of $1,660,974,272 in capital additions, net of adjustments (Exh. NG-AS-1, at 7-8). During that same period, National Grid incurred total cost of removal of $118,782,871 (Exh. NG-AS-1, at 8).

In Boston Gas Company/Colonial Gas Company, D.P.U. 14-132, at 136 (2015), the Department approved the Company's gas system enhancement plan ("GSEP") cost recovery mechanism pursuant to G.L. c. 164, § 145.[75] In National Grid's last base distribution rate case, the Department approved moving into rate base the GSEP investments placed in service from January 1, 2015 through December 31, 2016. D.P.U. 17-170, at 48. Since then, National Grid has made seven filings to support cost recovery for GSEP-related investments

[75] The GSEP mechanism, which is authorized by statute, is designed to recover annually, on a reconciling basis, the revenue requirement (including a return on investment, property taxes, and depreciation on capital investments made after January 1, 2015) to replace mains, services, meter sets, and other ancillary facilities composed of non-cathodically protected steel, cast iron, and wrought iron. G.L. c. 164, § 145; D.P.U. 14-132, at 3-4; M.D.P.U. No. 3.12, § 6.10. The Department also determined that copper as well as Aldyl-A pipe installed prior to 1985 should be included as eligible infrastructure. Boston Gas Company/Colonial Gas Company, D.P.U. 17-GSEP-03, at 31 (2018); Boston Gas Company/Colonial Gas Company, D.P.U. 18-GSEP-03, at 31-32 (2019).

made or projected to be made from January 1, 2017 to December 31, 2021, through the GSEP cost recovery mechanism. Boston Gas Company/Colonial Gas Company, D.P.U. 18-GREC-03 (2018); Boston Gas Company/Colonial Gas Company, D.P.U. 18-GSEP-03 (2019); Boston Gas Company/Colonial Gas Company, D.P.U. 19-GREC-03 (2019); Boston Gas Company/Colonial Gas Company, D.P.U. 19-GSEP-03 (2020); Boston Gas Company/Colonial Gas Company, D.P.U. 20-GREC-03 (2020); Boston Gas Company, D.P.U. 20-GSEP-03 (April 29, 2021); Boston Gas Company, D.P.U. 21-GREC-03 (Pending). In this filing, National Grid proposes moving into rate base GSEP investments placed in service from January 1, 2017 through March 31, 2020.

Specifically, in the instant proceeding, the Company proposed to include in rate base $601,523,485 for GSEP investments placed in service from January 1, 2017 through December 31, 2019 and $51,453,965 for GSEP investments placed in service from January 1, 2020 through March 31, 2020 ("Q1 2020 GSEP Investments") (Exhs. NG-AS-1, at 13-14; NG-RRP-1, at 15-16; DPU 10-3, Att. 2, at 15, 23, 33 & Att. 3, at 15, 23, 33; DPU 41-3, Att.).[76] During the proceeding, the Company revised its Q1 2020 GSEP investment plant in service to $53,297,137 (see Exh. DPU 41-3, Att. (Supp.)).

[76] $601,523,485 is the sum of Boston Gas GSEP investments of $201,709,083 (2017), $94,020,312 (2018), and $205,393,324 (2019), and former Colonial Gas GSEP investments of $41,058,196 (2017), $26,991,344 (2018), and $32,351,227 (2019) (see Exh. DPU 10-3, Att. 2, at 15, 23, 33 & Att. 3, at 15, 23, 33).

The Company continues to recover the revenue requirement on the cumulative GSEP investment outside of base rates (Exh. NG-RRP-1, at 16). Therefore, to prevent double recovery through the GSEP cost recovery mechanisms and base rates, National Grid proposes, upon approval of the proposed GSEP investment roll-in, i.e., October 1, 2021, to adjust the gas system enhancement adjustment factor ("GSEAF") to reflect nine-months from January 1, 2021 to September 30, 2021, of revenue requirement associated with the GSEP investments collected through the GSEAF before the investments are rolled into rate base and the revenue requirement collected through base distribution rates (Exh. NG-RRP-1, at 17).

In addition, the Company proposes to adjust rate base and depreciation expense to account for the additional depreciation expense of $22,975,284 and changes in ADIT of negative $3,121,778 associated with the proposed GSEP investment roll-in representing the period between the end of the test year, i.e., March 31, 2020, and the beginning of the rate year, i.e., October 1, 2021 (Exhs. NG-RRP-1, at 16-17; NG-RRP-2, Sch. 6, at 4 (Rev. 3); Sch. 11, at 1 (Rev. 3); WP NG-RRP-2, at 1 (Rev. 2)). The effect of these adjustments is a decrease of $19,853,507 to the Company's proposed rate base (see Exhs. NG-RRP-2, Sch. 6, at 4 (Rev. 3); Sch. 11, at 1 (Rev. 3); WP NG-RRP-2 (Rev. 2)).

2. Project Documentation

For the purposes of documentation, National Grid classified capital additions as either non-revenue-producing projects or revenue-producing projects (Exh. NG-AS-1, at 7-8). Non-revenue-producing projects are projects that involve the replacement of distribution infrastructure for system integrity purposes, such as the replacement of leak-prone pipe, and non-discretionary projects, such as system reinforcement, meter purchases, service replacements, and LNG infrastructure projects (Exh. NG-AS-1, at 8). Revenue-producing projects are those that add new customers to the system, such as main extension projects (Exh. NG-AS-1, at 8).

In its initial filing, the Company provided a summary and accompanying project documentation for all non-revenue and revenue-producing capital additions (that were not included for recovery in prior GSEP filings) over $100,000 for the period of January 1, 2017, through March 31, 2020, and sought for recovery in this case (Exh. NG-AS-1, at 9-12, citing Exhs. NG-AS-2 through NG-AS-5, NG-AS-2A through NG-AS-5A). National Grid also provided project documentation associated with leak-prone pipe previously reviewed or currently under review by the Department in annual GSEP filings (Exh. NG-AS-10).

3. Mid-Cape Replacement Project

The Mid-Cape main is a pipeline that runs from Sandwich to Chatham and provides gas service to much of Cape Cod (Exhs. NG-AS-1, at 9; NG-AS-Rebuttal-1, at 5-6). In 2014, the Company hired a consultant to inspect the Mid-Cape main and they found: (1) nine of 28 sampled welds were not acceptable under current American Petroleum Institute 1104 standards; (2) the documented diameter size of a 152-foot segment varied in diameter to the actual pipe size; (3) incomplete pressure test documentation; and (4) inadequately rated customer service regulators (Exh. NG-AS-Rebuttal-1, at 5-6). As a result, the Company lowered the pressure on the Mid-Cape main from 200 pounds per square inch gauge ("psig") to 124 psig and imposed a moratorium on new gas connections along the main (Exh. NG-AS-Rebuttal-1, at 7). The events that led up to this depressurization were the subject of an investigation by the Department's Pipeline Safety Division, docketed as D.P.U. 15-PL-04. As part of the resolution of that proceeding, the Company was assessed a fine of $1.25 million (Exh. AG 4-10, Atts. 20, at 21 & 22, at 8).

Subsequently, the Company replaced approximately 18 miles of existing steel main with new 12-inch steel main (Exh. NG-AS-Rebuttal-2, at 1). The new system is designed for maximum allowable operating pressure ("MAOP") of 270 psig with normal operation at 200 psig (Exh. NG-AS-Rebuttal-2, at 1). In the spring of 2019, the Company lifted the self-imposed moratorium on new gas connections along the Mid-Cape main (Exh. NG-AS-Rebuttal-1, at 7). The Company proposes to include approximately $81.4 million in capital additions associated with the Mid-Cape main replacement in rate base in this proceeding (Exhs. NG-AS-1, at 9). This amount reflects what the Company had spent on the Mid-Cape main replacement project as of March 31, 2020 (Exhs. NG-AS-1, at 9).

4. Positions of the Parties

a. Attorney General

i. Certain Revenue-Producing Projects

The Attorney General argues that the Department should disallow at least $14,870,103 in project costs for approximately 51 revenue-producing projects that had a negative post-construction internal rate of return ("IRR") and to direct the Company to amend its IRR and CIAC methodology (Attorney General Brief at 78, 80 n.94, citing Exh. AG-FWR, at 19). The Attorney General contends that nearly one quarter of revenue-producing projects constructed between 2010 and 2020 resulted in a negative post-construction IRR and that the Company knew that its IRR and CIAC methodology was deficient and yet failed to change the methodology since its last base distribution rate case (Attorney General Brief at 79-80). In general, the Attorney General asserts that the Company is either imprudently estimating revenue-producing project costs, thereby resulting in insufficient CIACs to make such projects meet the IRR threshold, or imprudently managing project costs once projects are underway (Attorney General Brief at 79).

In particular, the Attorney General points to calculation errors in the Company's IRR model, the allocation of bulk material charges to various projects, repeated increases in project scope, and repeated cost overruns as some of the alleged specific failures with the Company's IRR and CIAC methodologies (Attorney General Brief at 81-86, citing Exhs. NG-AS-Rebuttal-1, at 15-17; NG-AS-Rebuttal-3; DPU 36-10; DPU 36-14; DPU 36-17; DPU 36-18; DPU 36-19; DPU 36-24; DPU 36-25; RR-AG-7). According to the Attorney General, these examples demonstrate that the Company's IRR and CIAC methodologies are demonstrably deficient in calculating project costs and obtaining appropriate customer contributions to cover costs when necessary, and, therefore, imprudent (Attorney General Brief at 86). Further, the Attorney General contends that the Company's project-cost tracking for revenue-producing projects, which fails to allocate materials charges to individual projects, is insufficient to allow any meaningful prudency review by the Department of several projects (Attorney General Brief at 86). The Attorney General asserts that it is unclear why the Company did not recalculate or increase CIACs by termination or renegotiation of service agreements for those projects with cost increases that resulted in negative IRRs (Attorney General Brief at 85).

The Attorney General also argues that even if the Department allows recovery of the costs associated with the foregoing projects, it still should direct the Company to revise its IRR and CIAC methodologies going forward to better predict costs or to seek additional CIACs from customers when faced with unanticipated costs during construction (Attorney General Brief at 86-89). Specifically, the Attorney General asserts that the Department should direct the Company to: (1) regularly update the pricing and other assumptions underpinning its IRR model; and (2) more frequently exercise its existing service agreement rights to require additional CIACs from customers when needed to cover unanticipated costs and to amend its standard service agreements to explicitly expand the circumstances pursuant to which it will require additional CIAC (Attorney General Brief at 87-88).

ii. GSEP Projects

The Attorney General does not challenge any specific GSEP projects that the Company seeks to include in rate base. The Attorney General raised concerns regarding the interplay of cost recovery mechanisms and the PBR (Attorney General Brief at 19). The Department addresses this issue in Section IV.D.6 above.

iii. Mid-Cape Main Replacement Project

The Attorney General argues that cost recovery associated with the Mid-Cape main replacement project should be disallowed due to lack of proper documentation (Attorney

General Brief at 68). Specifically, the Attorney General contends that the Company failed to provide the requisite final closing report on the project, and instead provided only an "interim" closing report with its rebuttal testimony (Attorney General Brief at 70). According to the Attorney General, the Company's own internal project documentation procedures do not allow for or even mention the concept of an "interim" closing report (Attorney General Brief at 70). Further, the Attorney General argues that the interim closing report provided by the Company: (1) was unsigned by the internal sanctioning committee; (2) reveals that only five of seven closeout activities were completed; and (3) fails to contain any variance analyses, and instead provides only an anticipated cost variance analysis (Attorney General Brief at 69-70).

Additionally, the Attorney General argues that National Grid could have avoided or deferred much of the costs related to the Mid-Cape main replacement project had the Company built, operated, and maintained the original Mid-Cape main in a prudent manner, consistent with federal and state pipeline safety laws and regulations, and generally accepted utility practices (Attorney General Reply Brief at 32-33). In particular, the Attorney General points to the Department's investigation in docket D.P.U. 15-PL-04 where she contends that the Department found that the Company violated 15 federal and state pipeline safety laws and regulations with respect to the construction, operation, and maintenance of the original Mid-Cape main (Attorney General Brief at 71, citing Exhs. AG 4-10, Att. 20; AG 4-10, Att. 22). The Attorney General asserts that the Department also found that the Company failed to comply with 14 previous Department consent orders and ordered the Company to pay a civil penalty of $1.25 million (Attorney General Brief at 71, citing Exhs. AG 4-10, Att. 20, at 15; AG 4-10, Att. 22, at 5-6; AG 17-2, Att.). Finally, the Attorney General argues that the Company has mismanaged the Mid-Cape main by failing to: (1) detect that 30 services were over-pressurized for 16 years; (2) detect that recorded documentation of pipe sizes differed from actual conditions; (3) produce records of uprating, pressure testing, and changes to operating pressure; (4) provide written updated procedures for uprating; (5) install appropriate conforming welds; and (6) provide records to demonstrate that it conducted the mandatory continuing surveillance program (Attorney General Reply Brief at 32).

Based on the foregoing, the Attorney General recommends that the Department disallow the entire cost of the Mid-Cape main replacement project (Attorney General Brief at 70). If the Department does not disallow Mid-Cape main replacement costs entirely, the Attorney General argues that the amount allowed in rate base should be limited to the original cost of the Mid-Cape main (approximately $33 million) (Attorney General Brief at 71, 74).

b. Company

i. Introduction

National Grid asserts that it has properly supported the net plant in service through the end of the test year with actual computations and thousands of pages of supporting documentation, including project cover sheets, approved amounts, actual costs, cost variance information, project sanction, re-sanction, and closure papers (Company Brief at 200, 207-210, citing Exhs. NG-AS-1, at 2-4, 7-8, 10-12; NG-AS-2; NG-AS-2A; NG-AS-3; NG-AS-3A; NG-AS-4; NG-AS-4A; NG-AS-5; NG-AS-5A; NG-AS-6; NG-AS-7; NG-AS-8; NG-AS-8A; NG-AS-9; NG-AS-9A; NG-AS-10; AG 5-6 & Atts.; AG 16-6; AG 54-27). Further, National Grid contends that it has provided a detailed explanation of the Company's planning, allocations, and cost-containment procedures with respect to capital expenditures (Company Brief at 200-206, 208-211, citing Exhs. NG-AS-1, at 8, 11-12; 16-21; AG 5-1 & Atts.; AG 21-3). National Grid asserts that the costs associated with the capital additions submitted for approval are prudently incurred and that the projects are used and useful in providing service to customers (Company Brief at 200).

ii. Certain Revenue-Producing Projects

National Grid argues that the Attorney General's position regarding revenue-producing projects with negative post-construction IRRs is unreasonable (Company Brief at 223). The Company notes that it uses a pre-construction IRR when determining how to seek recovery of the associated costs of a project (Company Brief at 223). Therefore, according to the Company, the determination of whether the Company is prudent in undertaking a particular project primarily rests on the decision to undertake the project at its outset (Company Brief at 223). The Company maintains that costs should be eligible for recovery if the Company exercises cost management throughout a project, even if there are cost overruns (Company Brief at 223-224). National Grid points out five categories of projects that resulted in negative IRRs: (1) projects that were estimated using an IRR model that the Company later discovered to have calculation errors; (2) projects that involved contractor material charges intended for more than one project charged against only a small handful of projects; (3) projects that experienced a change in scope; (4) projects that experienced unanticipated cost changes; and (5) projects completed during the labor dispute with its two largest unions (Company Brief at 225). National Grid argues that it has reviewed project documentation to ensure that reasons for the cost variances reasonably fell outside the Company's control and has shown that the plant is used and useful and should be included in rate base (Company Brief at 227-228).

iii. GSEP Projects

The Company asserts that it has submitted in the annual GSEP-related filings associated documentation for GSEP plant put in service from January 1, 2017 through December 31, 2019 pursuant to G.L. c. 164, § 145 (Company Brief at 207). The Company maintains that the Department has already reviewed and approved the GSEP investments made from January 1, 2017 through December 31, 2019, in the annual GSEP-related filings (Company Brief at 211, citing Exh. NG-AS-1, at 14). National Grid also contends that for capital projects placed in service on or after January 1, 2020, it has provided in this proceeding the same supporting documentation as that provided in the pending GSEP reconciliation ("GREC") proceeding (Company Brief at 207-208, citing Exh. DPU 41-4, Supp; D.P.U. 21-GREC-03). National Grid argues that the Department has previously determined that the Company may transfer recovery of prior GSEP investments through base distribution rates during a base distribution rate case (Company Brief at 211, citing D.P.U. 18-GSEP-03, at 40-41). The Company maintains that it has provided the analysis and documentation to support the prudency of the GSEP projects in this proceeding, and the Department should approve the inclusion of the GSEP plant additions in rate base for the period January 1, 2017 through March 31, 2020 (Company Brief at 211-212).

iv. Mid-Cape Main Replacement Project

The Company argues that costs for the Mid-Cape main replacement project were prudently incurred and that it has provided the proper supporting documentation (Company Brief at 214). The Company points out that the decision to undertake the project was prudent because the main project drivers were pipeline integrity and safety, as well as a Department directive in docket D.P.U. 15-PL-04 to repair, upgrade, and replace the 200 psig pipeline (Company Brief at 222, citing Exh. NG-AS-Rebuttal-1, at 11). The Company also argues that it already was penalized by the Department as part of the investigation in D.P.U. 15-PL-04 and should not be penalized twice through disallowance of project costs (Company Brief at 222, citing Exh. NG-AS-Rebuttal-1, at 11).

In response to the Attorney General's issue with the interim project closure reports, the Company argues that the Department does not specify what the document should be called, and that the word "interim" in the title simply refers to the fact that the project is not yet complete (Company Brief at 219). The Company notes that the documentation shows that the project is in service, used and useful, and includes a variance analysis (Company Brief at 219). Therefore, the Company asserts that the project satisfies the Department's standard for inclusion in rate base (Company Brief at 219).

5. Standard of Review

For costs to be included in rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to earn a return. D.P.U. 85-270, at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. D.P.U. 95-118, at 39-40; D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also Massachusetts Electric, 376 Mass. 294, 304; Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967).[77] In addition, the Department has stated:

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

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

6. Analysis and Findings

a. Certain Revenue-Producing Projects

As noted above, the Attorney General argues that the Department should disallow at least $14,870,103 in project costs for dozens of revenue-producing projects that had a

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

negative post-construction IRR and to direct the Company to amend its IRR and CIAC methodologies (Attorney General Brief at 78). The Department has reviewed the documentation associated with these projects and we find that while there was an unusual number of projects that resulted in negative IRRs, the Company adequately described and explained the reasons why the projects resulted in negative IRRs (see, e.g., Exhs. NG-AS-Rebuttal-1, at 14-17; NG-AS-Rebuttal-3; NG-AS-Rebuttal-4; DPU 36-7; DPU 36-9; DPU 36-10; DPU 36-11; DPU 36-13; DPU 36-15 through DPU 36-19; DPU 36-24 through DPU 36-27). Further, we find no evidence of imprudence on the Company's part (Exhs. NG-AS-1, at 7-9, 11-12; NG-AS-Rebuttal-1, at 12-18; NG-AS-2; NG-AS-2A; NG-AS-4; NG-AS-4A; NG-AS-8; NG-AS-8A; NG-AS-9; NG-AS-9A; DPU 36-7 through DPU 36-19; DPU 36-24 through DPU 36-27; AG 30-1 through AG 30-4; AG 30-8 through AG 30-16).

The Department, however, strongly encourages the Company to examine its IRR and CIAC methodologies and to make appropriate revisions to decrease the occurrences of revenue-producing projects resulting in negative post-construction IRRs. While we decline to adopt the Attorney General's recommendations as directives, we note that they appear to be reasonable, and we urge the Company to consider these and other changes to its IRR and CIAC procedures or risk future disallowance of recovery of those investments.

b. GSEP Projects

The Department has previously found in the Company's annual GREC filings that the GSEP investments placed into service between January 1, 2017 and December 31, 2019 were prudently incurred and used and useful in providing service to ratepayers. D.P.U. 18-GREC-03, at 29-30; D.P.U. 19-GREC-03, at 22-23; D.P.U. 20-GREC-03, at 18. Additionally, the Company's proposal to roll these investments into rate base is consistent with Department precedent. D.P.U. 19-120, at 165; D.P.U. 17-170, at 40 n.25, 47-48. For these reasons, the Department allows the inclusion of GSEP investments placed into service between January 1, 2017 and December 31, 2019 in the Company's rate base.

Next, the Department addresses the Company's proposal to include the Q1 2020 GSEP Investments in plant in service. Pursuant to G.L. c. 164, § 145, the prudence review for GSEP investments is conducted outside of a base distribution rate proceeding for investments made in a single calendar year (e.g., the D.P.U. 21-GREC-03 proceeding includes a prudence review for GSEP investments that went into service during calendar year 2020). As of April 30, 2021, National Grid recovered planned 2020 GSEP investment costs through its GSEAF that included actual costs for GSEP investment made 2017 through 2019 and estimated costs through 2020 GSEP investment. D.P.U. 19-GSEP-03, at 1, 30-31. The Department's prudence review of the Company's 2020 GSEP investments is currently pending, and the Department's decision in that matter is not expected to issue until October 31, 2021, one month after the date of this Order. See D.P.U. 21-GREC-03.[78] In that decision, the Department will determine the appropriateness of the Company either

[78] National Grid filed its petition for recovery of its 2020 GSEP investments on April 30, 2021, and GREC proposals have a statutory six-month review period pursuant to G.L. c. 164, § 145(e).

recovering from or crediting to customers through GSERAFs for under- or over-collection of costs to replace eligible aging or leaking natural gas infrastructure. To ensure accurate accounting of the 2020 GSEP investment reconciliation, the Department finds it appropriate to review the full 2020 GSEP investment in the current pending GREC proceeding.[79] Moving the Q1 2020 GSEP investments into rate base at this time contradicts the operation of the GSEP mechanism. G.L. c. 164, § 145(f), (g).

Further, by asking the Department to conduct a prudence review for the Q1 2020 GSEP Investments here, the Company is requesting that the Department expedite its prudence review of the Q1 2020 GSEP Investments in this proceeding in addition to the prudence review that must occur in the D.P.U. 21-GREC-03 proceeding. The Company states that reviewing the Q1 2020 GSEP Investments in this rate case still allows the Department to determine the prudence of Q1 2020 GSEP Investments in the current GREC proceeding (Exh. DPU 26-1). The Department has previously determined that where plant additions are found to have been prudently incurred and thus moved into rate base, the Department will not allow re-litigation of those plant additions in subsequent proceedings. D.P.U. 92-210-B

---

79 Further, according to the Company, the repair deduction percentages for the Q1 2020 GSEP Investments are estimates, and the updated actual information will not be available until the Company files its next tax return (Exh. DPU 41-3 & Att. (Supp.); Tr. 8, at 1008-1009). Thus, National Grid's proposed rate base adjustment for the Q1 2020 GSEP Investments is based on an estimate and therefore speculative.

at 13-14.[80] In addition, it is inefficient and administratively burdensome to review the same GSEP-related costs in two proceedings.

For the reasons above, the Department finds that the inclusion of the Q1 2020 GSEP Investments in base distribution rates is not allowed at this time. Instead, the Company shall continue to recover costs associated with the Q1 2020 GSEP Investments through the GSEP cost recovery mechanisms. Accordingly, the Department directs the Company to reduce plant in service by $53,297,137 to remove the Q1 2020 GSEP Investments. In recognition of the Department's decision to exclude these plant additions from rate base, a corresponding adjustment to the Company's depreciation reserve is required. D.P.U. 14-150, at 94; D.P.U. 10-55, at 193-194; D.P.U. 08-27, at 16-17. Thus, the Department directs the Company to reduce accumulated depreciation by $2,158,204 and ADIT by $13,098,044 (Exh. WP NG-RRP-2, at 1 (Rev. 2)). Further, to reflect the exclusion of the Q1 2020 GSEP Investments, the Department directs the Company to reduce depreciation expense for the affected accounts.[81] Accordingly, the Department directs the Company to include a revised GSEAF in the Company's compliance filing.

---

80 Conversely, the Department has authority to review plant previously included in rate base but no longer used and useful. Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 578 (1978); D.P.U. 92-210-B at 14.

81 The adjustments to depreciation expense should reflect the updated plant balance of affected accounts multiplied by the depreciation accrual rate approved by the Department in the instant proceeding. For the purposes of plant disallowance, the $53,297,137 reduction to plant associated with Q1 2020 GSEP investments is allocated proportionally as a reduction of: (1) $33,058,363 to Account 367; (2) $16,565,559 to Account 380; (3) $2,128,750 to Account 381; (4) $1,416,978 to Account 382; and (4) $127,487 to Account 383. The total adjustment to depreciation

c. Mid-Cape Main Replacement Project

The replacement of the Mid-Cape main was performed in three phases, with the following in service dates: (1) the main in Yarmouth and Dennis was placed in service on November 22, 2019; (2) the main in Harwich was placed in service on December 13, 2019; and (3) the main in Brewster was placed in service on May 29, 2020 (Exh. NG-AS-Rebuttal-1, at 8-9). The only work remaining on the project is roadside restoration from paving work (Exh. NG-AS-Rebuttal-1, at 8-9). The Department is satisfied that, based on the record, the replacement project costs were prudently incurred, and the project is used and useful (Exhs. NG-AS-1, at 16; NG-AS-Rebuttal-1, at 2-12; NG-AS-Rebuttal-2; NG-AS-5; NG-AS-5A; NG-AS-9; NG-AS-9A; AG 5-4 through AG 5-14; AG 21-8; AG 21-9; AG 24-3; AG 45-1; Tr. 2, at 157-177, 235-237; Tr. 12, at 1227-1237). In this regard, we are not persuaded that the Company's use of "interim" reports warrants a disallowance of costs, as the Attorney General suggests (Attorney General Brief at 68-70). Rather, we are satisfied that these reports were intended to convey that additional work was needed before the project could be closed out (Exh. NG-AS-Rebuttal-1, at 3-4).

Notwithstanding these findings, the Department also concludes that there were significant and fundamental deficiencies in the Company's management of the Mid-Cape main (Exhs. AG 4-10, Atts. 20, 22; AG 4-24, Att. 15; AG 5-12; Tr. 2, at 169, 173-174, Tr. 12, at 1226-1237). The Company failed to detect the over-pressurization of at least 30 services

---

expense discussed in Section VIII.B.3.g below includes the impact of these plant disallowances.

without proper over-pressure protection for approximately 16 years (i.e., 1998 to 2014) (Exh. AG 4-10, Atts. 20, 22; Tr. 2, at 169, 173-174, Tr. 12, at 1226-1237). The Company acknowledges that had these conditions not occurred, the original Mid-Cape main would not have required replacement (Exh. AG 5-5, Att. 2, at 8, Att. 3, at 7; Tr. 2, at 173-174, Tr. 12, at 1231-32).

Much of the record evidence on the prudency of National Grid's management of the Mid-Cape main comes from the critical assessments by the Department in the July 23, 2015, Notice of Probable Violation ("NOPV") in docket D.P.U. 15-PL-04. The Department notes that the Company failed to: (1) protect service line from over pressurization, (2) operate distribution mains in compliance with 49 C.F.R. Part 192, (3) inspect corrosion control systems, and (4) follow procedures regarding surveillance program and revised class location (Exh. AG 4-10, Att. 20, at 4-12). This NOPV resulted in a fine of $1.25 million (Exh. AG 4-10, Att. 22, at 6).

While the decision to replace the Mid-Cape main may have been prudent based on the condition of the main, this decision cannot be isolated from the fact that the Mid-Cape main was in poor condition and prematurely retired due to the mismanagement on the part of the Company. Consequently, while the Department will allow the Company to recover the costs of the Mid-Cape main replacement project, the Company will not be allowed to earn a return on this investment. The Department finds that this disallowance adequately and appropriately holds the Company accountable for the increased costs that could have been avoided had the Mid-Cape main been properly maintained. Where shareholders have been appropriately compensated for risk through the allowed rate of return, recovery of a return on the unamortized plant balance that has been prematurely retired would represent an inappropriate shift of risk to ratepayers. Western Massachusetts Electric Company, D.P.U. 97-120, at 31 (1999); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 64 (1983). The disallowance of a return on unrecovered plant balances would not in and of itself be confiscatory. D.P.U. 97-120, at 31. The dollar amount of the return, after-taxes, is approximately \$5.5 million per year or 0.26 percent of the Company's \$2.12 billion common equity balance (Exh. NG-RRP-5, at 6 (Rev. 3)). Accordingly, the Department directs the Company to remove \$81,363,794 in plant in service, \$2,408,368 in accumulated depreciation, and \$134,983 in ADIT.[82] These adjustments are reflected in the Department's Schedule 4 below.

[82] The \$81,363,794 reduction to utility plant in service is reflected by the total costs of the Mid-Cape project as of March 31, 2020 (Exh. NG-AS-1, at 9). The \$2,408,368 reduction to accumulated depreciation is calculated by applying the annual accrual rate of account 367.14 (i.e., 2.96 percent) to the Mid-Cape project balance as of March 31, 2020 (Exh. AG 3-36, Att. 2). Finally, the \$134,983 reduction to ADIT is calculated by taking the difference in the accelerated depreciation rate of 3.75 percent and the book depreciation rate of 2.96 percent, applying the resulting 0.79 percent to the to the Mid-Cape balance as of March 31, 2020, and finally applying the 21 percent tax rate ((0.0375-0.0296)*\$81,363,794*0.21) (RR-DPU-44, Att.). After removing the accumulated depreciation and ADIT balances from the Mid-Cape project costs, the resulting balance is \$78,820,443. Applying the WACC of 6.98 percent approved in this proceeding yields the return component of the Mid-Cape project of \$5,501,667.

d. Remaining Projects

For non-revenue-producing projects greater than $100,000, National Grid provided a list of projects categorized by number and associated in-service dates, authorized pre-construction cost estimates, actual project costs, and cost variances (Exhs. NG-AS-1, at 7-8; NG-AS-3; NG-AS-3A; NG-AS-5; NG-AS-5A). For all revenue-producing projects greater than $100,000, National Grid's project list included the same information, as well as pre- and post-construction IRRs (Exhs. NG-AS-1, at 7-8; NG-AS-2; NG-AS-2A; NG-AS-4; NG-AS-4A).

For each of the projects greater than $100,000,[83] National Grid provided supporting documentation, as applicable, including: (1) a cover page identifying the project number; (2) a project authorization detail form that provides basic information about the project, including the project type, the project location, and whether the project is revenue producing or non-revenue producing; (3) the project authorization; (4) a variance analysis for any project with a variance between actual and estimated project costs that exceeds ten percent; and (5) a capital project closure report that identifies the costs of the project by type and year (Exhs. NG-AS-1, at 7-13; NG-AS-2 through NG-AS-10; NG-AS-2A through NG-AS-5A; NG-AS-8A; NG-AS-9A). National Grid also provided documentation containing sanction authorization, closure papers, and variance analyses for revenue-producing projects greater

[83] The Company maintains documentation for all capital projects, but due to the volume of documentation, has provided only the documentation for projects in excess of $100,000 (Exh. NG-AS-1, at 4, 8). No intervenor challenged any of the projects with costs under $100,000.

than $100,00 (Exhs. NG-AS-1, at 7-13; NG-AS-2; NG-AS-2A; NG-AS-4; NG-AS-4A; NG-AS-8; NG-AS-8A; NG-AS-9; NG-AS-9A).

National Grid provided appropriate project documentation for the various categories of proposed plant additions. The Department has reviewed the documentation provided for the projects National Grid proposes to include in rate base, and, subject to our findings above, we conclude that the project costs were prudently incurred, and the projects are used and useful. Finally, we note that National Grid follows a capital budgeting and authorization process to manage its capital projects and assure cost containment (Exh. NG-AS-1, at 16-21). In accordance with the authorization policy, projects that are estimated to cost more than $1 million require delegation of authority approval, which involves a formal review and sanctioning documentation (Exh. NG-AS-1, at 18). National Grid explains that projects estimated to cost between $8 million and $25 million are reviewed with additional scrutiny provided by the U.S. sanctioning committee and a senior executive sanctioning committee (Exh. NG-AS-1, at 18). Further, National Grid explains that projects estimated to cost less than $1 million do not require formal sanctioning through its U.S. sanctioning committee and, instead, are approved through a supervisory delegation of authority hierarchy based on certain established thresholds (Exh. NG-AS-1, at 19). During the course of a particular project or program, National Grid controls costs and maintains oversight at multiple levels (Exh. NG-AS-1, at 16-21). National Grid's finance department produces a monthly capital by category report, which monitors monthly and year-to-date cost comparisons between actual and budgeted costs (Exh. NG-AS-1, at 20-21). National Grid's resource planning department, project management department, and budget sponsors review the report to monitor variances between actual and budgeted costs (Exh. NG-AS-1, at 20-21). All projects whose costs have exceeded their authorized spending amount require a gas overrun report, a written plan to improve the prudency of the project, and an additional sanctioning authorization in accordance with the initial sanctioning procedure (Exh. NG-AS-1, at 20-21). The Department finds that National Grid's project authorization and review policy and cost control measures are reasonable and appropriate.

C. Cash Working Capital

1. Introduction

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; Western Massachusetts Electric Company, D.P.U. 87-260, at 22 (1988). The Department currently requires all gas and electric companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 164 (2011). In the event that the lead-lag factor is not below 45 days, companies will bear a heavy burden to justify the reliability of such a study and the reasonableness of the steps the company has taken to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

The Company conducted a lead-lag study to determine total working capital requirements.[84] Initially, the Company determined working capital requirements of $52,293,865 and $8,337,893 for Boston Gas and the former Colonial Gas, respectively (Exhs. NG-RRP-1, at 95; NG-RRP-3-BOS at 1; NG-RRP-3-COL at 1). During the proceeding, the Company made revisions and proposed working capital requirements of $53,162,281 and $8,596,749 for Boston Gas and the former Colonial Gas, respectively, for a total requirement of $61,759,030 (Exhs. NG-RRP-3-BOS at 1 (Rev. 3); NG-RRP-3-COL at 1 (Rev. 3); NG-RRP-5, at 7-8 (Rev. 3)). To derive the cash working capital allowance, the Company analyzed the significant cash inflows and outflows of Boston Gas and the former Colonial Gas and developed lead-lag factors for the Company's overall revenues and expenses (Exhs. NG-RRP-1, at 97; NG-RRP-3-BOS (Rev. 3); NG-RRP-3-COL (Rev. 3)). National Grid used cash transactions and invoices for the test year, and the calculated revenue lag and expense lead were applied to rate year expenses (Exhs. NG-RRP-1, at 96; NG-RRP-3-BOS (Rev. 3); NG-RRP-3-COL (Rev. 3)).

---

84 A lead-lag study is an accepted tool for a company to determine the amount of working capital that it must reserve. Western Massachusetts Electric Company, D.P.U. 1300, at 20 (1983). The lead-lag study also compares the time the company has to pay its bills. D.P.U. 1300, at 20. Lead time is the number of days between the company's receipt and payment of invoices it receives (Exh. NG-RRP-1, at 97). Lag time is the average number of days between a company's billing of its customers and its receipt of payment (Exh. NG-RRP-1, at 97).

National Grid considered two broad categories of lags and leads in its cash working capital allowance: (1) lag time associated with the collection of revenues owed to the Company (i.e., revenue lags); and (2) lead times associated with the payments for goods and services received by the Company (i.e., expense leads) (Exh. NG-RRP-1, at 97).

The distribution revenue lag measured the number of days from the date service was rendered by the Company to the date payment was received from such customers and such funds were deposited and available to the Company (Exh. NG-RRP-1, at 97). In the lead-lag study, the revenue lag was divided into three components: (1) service lag; (2) billing lag; and (3) collections lag (Exh. NG-RRP-1, at 97-98). Service lag refers to the number of days from the midpoint of the service period to the meter reading date for that service period; using the midpoint methodology, the average lag associated with the provisioning of service for both Boston Gas and the former Colonial Gas was 15.21 days (Exhs. NG-RRP-1, at 98; NG-RRP-3-BOS at 2 (Rev. 3); NG-RRP-3-COL at 2 (Rev. 3)). Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed, and it was found to be 1.44 days for both Boston Gas and the former Colonial Gas (Exhs. NG-RRP-1, at 98; NG-RRP-3-BOS at 2 (Rev. 3); NG-RRP-3-COL at 2 (Rev. 3)). Collections lag refers to the average amount of time from the date when the customer received a bill to the date the Company received payment, and it was found to be 48.84 days for Boston Gas and 39.69 days for the former Colonial Gas (Exhs. NG-RRP-1, at 99; NG-RRP-3-BOS at 2 (Rev. 3); NG-RRP-3-COL at 2 (Rev. 3)). Summing the three lags results in a total lag of 65.49 days (17.94 percent) for Boston Gas and 56.34 days

(15.44 percent) for the former Colonial Gas (Exhs. NG-RRP-1, at 100; NG-RRP-3-BOS at 2 (Rev. 3); NG-RRP-3-COL at 2 (Rev. 3)).[85]

Lead times associated with the following expense categories were considered in the lead-lag study: (a) O&M expenses; (b) municipal taxes; and (c) payroll taxes (Exhs. NG-RRP-1, at 100; NG-RRP-3-BOS at 3 (Rev. 3); NG-RRP-3-COL at 3 (Rev. 3)). In particular, O&M expenses are the costs to the Company of providing service to customers and administering the Company's operations (Exh. NG-RRP-1, at 100). The following expenses are also included in the study: (1) payroll; (2) service company charges; and (3) other O&M expenses (Exhs. NG-RRP-1, at 100; NG-RRP-3-BOS at 3 (Rev. 3); NG-RRP-3-COL at 3 (Rev. 3)).

The Company uses the O&M expense as an example of associated lead-lag, which results in a net lag of 12.09 percent for Boston Gas and 9.89 percent for the former Colonial Gas Company (Exhs. NG-RRP-3-BOS at 3 (Rev. 3); NG-RRP-3-COL at 3 (Rev. 3)).[86] The net lag is calculated for each expense component by subtracting that expense's payment lead

---

85 Percentages are calculated by dividing the total lag by the number of days in the test year: 65.49/365=0.1794.

86 The Company also developed net lag percentages for the following categories of expense: (1) municipal taxes; (2) payroll taxes – employer federal unemployment; (3) payroll taxes – employer state unemployment; (4) payroll taxes – Federal Insurance Contribution Acts ("FICA") expense (weekly); (5) payroll taxes – FICA expense (monthly); (6) payroll taxes – employee FICA and federal withholding (weekly); (7) payroll taxes – employee FICA and federal withholding (monthly); (8) payroll taxes – employee state income tax withholding (weekly); and (9) payroll taxes – employee state income tax withholding (monthly) (Exhs. NG-RRP-3-BOS (Rev. 3); NG-RRP-3-COL (Rev. 3)).

or lag from the revenue lag (Exhs. NG-RRP-3-BOS at 3 (Rev. 3); NG-RRP-3-COL at 3 (Rev. 3)). The average lag for the payment of O&M expenses is 21.35 days (5.85 percent) for Boston Gas and 20.24 days (5.55 percent) for the former Colonial Gas (Exhs. NG-RRP-3-BOS at 3 (Rev. 3); NG-RRP-3-COL at 3 (Rev. 3)). For Boston Gas, the difference between the revenue collection lag of 17.94 percent and the O&M payment lag of 5.85 percent is a net lag of 12.09 percent (Exh. NG-RRP-3-BOS at 3 (Rev. 3)). For the former Colonial Gas, the difference between the revenue collection lag of 15.44 percent and the O&M payment lag of 5.55 percent is a net lag of 9.89 percent (Exh. NG-RRP-3-COL at 3 (Rev. 3)). These percentages are then multiplied by the rate year O&M expense, resulting in cash working capital allowances for O&M expenses for the rate year of $37,340,066 and $6,310,903 for Boston Gas and the former Colonial Gas, respectively (Exhs. NG-RRP-3-BOS at 1 (Rev. 3); NG-RRP-3-COL at 1 (Rev. 3)). This process is then repeated for all other expense items listed, resulting in total cash working capital allowances of $53,162,281 and $8,596,749 for Boston Gas and the former Colonial Gas, respectively (Exhs. NG-RRP-3-BOS at 1 (Rev. 3); NG-RRP-3-COL at 1 (Rev. 3)).

2. Positions of the Parties

On brief, National Grid summarizes its revised calculation of the cash working capital requirements and asserts that the Department should adopt the Company's lead-lag results and proposed cash working capital allowance (Company Brief at 94-96). No intervenor addressed this issue on brief.

3. Analysis and Findings

The Department has reviewed the record in support of National Grid's lead-lag study, and we conclude that the Company properly calculated the net lag percentages for each of the expense categories included in the cash working capital requirements (Exhs. NG-RRP-3-BOS at 1 (Rev. 3); NG-RRP-3-COL at 1 (Rev. 3)). Accordingly, the Department accepts the Company's lead-lag study and the resulting net lag percentages used to derive the cash working capital requirement. Application of the net lag percentages to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $51,392,205 for Boston Gas and $7,991,856 for the former Colonial Gas, as shown in Schedules 6A and 6B below.

D. Conclusion

Based on the foregoing, the Department accepts the Companies' proposals to include its proposed projects placed in service from January 1, 2017 through March 31, 2020 in rate base, with the exception of the Q1 2020 GSEP investments as well as the Mid-Cape main replacement project. As a result, the Department approves $1,526,313,341[87] in plant additions resulting in a total utility plant in service of $6,349,144,527 for the purposes of calculating return on rate base.

87 $1,660,974,272 - $53,297,137 - $81,363,794 = $1,526,313,341

VII. EXCESS ACCUMULATED DEFERRED INCOME TAXES

A. Introduction

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 ("2017 TCJA") was signed into law.[88] Among other things, the 2017 TCJA reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. Pub. L. No. 115-97, § 13001. On February 2, 2018, the Department, pursuant to G.L. c. 164, §§ 76, 93, 94 and G.L. c. 165, §§ 2, 4, opened an investigation into the effect on rates of the decrease in the federal corporate income tax rate on the Department's regulated utilities. Effect of Reduction in Federal Income Tax Rates on Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15, Order Opening Investigation (February 2, 2018).[89]

The Department determined, among other things, that for certain regulated utilities, including the Company, the reduction in the federal corporate income tax rate resulted in booked ADIT that was in excess of future liabilities. D.P.U. 18-15, Order Opening Investigation at 4. Thus, as part of the investigation, certain regulated utilities, including the Company, were directed to file a proposal to refund to ratepayers the balance of excess ADIT as of December 31, 2017. D.P.U. 18-15, Order Opening Investigation at 5. On September 24, 2018, the Department issued an Order and approved the Company's proposal

---

88 Pub. L. No. 115-97, 131 Stat. 2054: An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018.

89 For a complete background and procedural history, refer to D.P.U. 18-15-A at 1-7.

to return to ratepayers the balance of protected excess ADIT. D.P.U. 18-15-D at 17-21.[90] The Department also approved the Company's proposed 50-year amortization period applicable to protected excess ADIT, subject to further adjustment as necessary. D.P.U. 18-15-D at 18-19.

B. Company Proposal

In the instant proceeding, National Grid reports that Boston Gas' protected excess ADIT balance is $124,288,298, and that the annual passback amount to customers is $2,366,542, which reflects an amortization period of 52.5 years (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3)). National Grid reports that the former Colonial Gas' protected excess ADIT balance is $34,474,027, and that the annual passback amount to customers is $876,870, which reflects an amortization period of 39.3 years (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3)).

National Grid also reports excess ADIT associated with net operating losses ("NOL") (i.e., "NOL-related excess ADIT") in the amount of negative $24,741,846 for Boston Gas (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3)). The Company proposes an annual amount of negative $2,366,542 in NOL-related excess ADIT, which will completely offset the annual passback of $2,366,542 in excess ADIT (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3)). National Grid reports NOL-related excess ADIT in the amount of negative $4,359,667 for the former

90 The Internal Revenue Service classifies certain plant-related excess ADIT as "protected" and subject to specific normalization rules. Pub. L. No. 115-97 § 1561(d) (1), (2). Excess ADIT that is not classified as "protected" is commonly referred to as "unprotected."

Colonial Gas (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3)). The Company proposes an annual amount of negative $871,933 in NOL-related excess ADIT, which will offset nearly all of the annual passback of $876,870 in excess ADIT (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3).[91]

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Company's NOL-related excess ADIT balance should be amortized over the same timeframe as the amortization periods applicable to Boston Gas' and the former Colonial Gas' respective plant-related excess ADIT balance (Attorney General Brief at 144, citing Exhs. AG-DJE-1, at 13-14 & Sch. 3).[92] In this regard, the Attorney General contends that the period of time over which the Company anticipates utilizing its NOL balance has no bearing on the NOL balance utilization (Attorney General Brief at 143, citing Exh. AG-DJE-1, at 12-13; Attorney General Reply Brief at 69).

---

[91] National Grid's proposed NOL-related excess ADIT amortization period is calculated by taking the average of Boston Gas' and the former Colonial Gas' tax loss amortization periods that are derived from the NOL-related excess ADIT balance as of January 1, 2018, divided by the proposed annual amortization amount for each company. Based on the record, the average for Boston Gas was 11.79 years and the average for the former Colonial Gas was 7.42 years, for a combined average of 9.6 years (see Exhs. NG-RRP-2, Sch. 10, at 5 (Rev. 3); DPU 6-5, Att.).

[92] The Attorney General contends that the appropriate amortization period for the NOL-related excess ADIT balance is 49 years when viewing Boston Gas and the former Colonial Gas as a consolidated entity (Attorney General Brief at 144, citing Exh. AG-DJE-1, at 13-14). If the operating companies are viewed separately, the Attorney General contends that the proper amortization periods for the NOL-related excess ADIT are 52.5 years for Boston Gas and 39.3 years for the former Colonial Gas (Exh. AG-DJE-1, Sch. 3).

In particular, the Attorney General asserts the NOL-related excess ADIT is a debit balance (i.e., an asset), and as a result of the 2017 TCJA, the Company's NOL balance is utilized at the 21 percent tax rate instead of the 35 percent pre-2017 TCJA tax rate (Attorney General Brief at 141-142). She also claims that the Company's NOL was incurred largely because of bonus depreciation and capital repair deductions before 2017 TCJA (Attorney General Brief at 141). On the other hand, the Attorney General states that the protected excess ADIT balance is a credit balance (i.e., liability) related to accelerated depreciation and bonus depreciation (Attorney General Brief at 140-142, citing Exhs. NG-RRP-2, Sch. 10, at 6, 7; AG-DJE-1, at 9). Thus, according to the Attorney General, the Company uses NOL-related excess ADIT as a direct offset to the plant-related excess ADIT (Attorney General Brief at 140-142, citing Exhs. NG-RRP-2, Sch. 10, at 6, 7; AG-DJE-1, at 9, 12). The Attorney General notes that the Company's proposed NOL-related excess ADIT amortization almost completely offsets the annual passback of the protected excess ADIT so that there is virtually no amount of passback to current ratepayers (Attorney General Brief at 142). The Attorney General therefore argues that the Company's proposal creates intergenerational inequity by denying current ratepayers the benefit of the protected excess ADIT passback (Attorney General Brief at 143, citing Exhs. AG-DJE-1, at 13; AG-DJE-Surrebuttal-1, at 4; Attorney General Reply Brief at 70, citing Exh. NG-RRP-2, Sch. 10, at 5; Tr. 8, at 954).

Further, the Attorney General argues that the period over which the Company anticipates utilizing its NOL balance is questionable because the Company's claim that it will have adequate taxable income to utilize the NOL is uncertain (Attorney General Reply Brief at 69). The Attorney General maintains that the NOL balance is utilized prospectively whenever there is a taxable income, and that the NOL-related excess ADIT amortization has absolutely no relationship to the NOL balance utilization (Attorney General Brief at 141-143, citing Exhs. AG-DJE-1, at 12; NG-RRP-2, Sch. 10, at 6-7). In particular, the Attorney General contends the Company provided no evidence to demonstrate that it will have taxable income going forward to utilize the NOL balance and, in fact, in fiscal year 2020, the Company did not utilize any of its NOLs because the consolidated group was in a tax loss position (Attorney General Reply Brief at 69, citing Tr. 8, at 949-951).

Next, the Attorney General contends that there is no evidence of other utility companies in Massachusetts besides National Grid affiliates that amortize the NOL-related excess ADIT in the same manner as the Company proposes in this proceeding (Attorney General Brief at 144, citing Tr. 8, at 956-957). She notes, however, that National Grid's affiliate in Rhode Island, Narragansett Electric Company, is amortizing the NOL-related excess ADIT proportionally to the protected plant amortization (Attorney General Brief at 144, citing Tr. 8, at 956-957). Finally, the Attorney General argues that the Company's comparison of the amortization of the NOL-related excess ADIT to its treatment of uninsured claims expense is irrelevant because the uninsured claims expense is determined independently and is not calculated to offset the protected Excess ADIT passback (Attorney General Reply Brief at 70).

2. Company

National Grid claims that its treatment of NOL-related excess ADIT in the context of the NOL balance utilization is based on Department precedent in D.P.U. 18-150, where the Company notes the Attorney General made the same argument to put the amortization of the NOL-related excess ADIT on the same schedule as the amortization of the protected excess ADIT (Company Reply Brief at 57, citing D.P.U. 18-150, at 196). Thus, National Grid argues that the Attorney General's assertions are unfounded, and because the Company's proposed amortization period of the NOL-related excess ADIT matches the expected life of the underlying NOL, the Department should approve its proposal (Company Brief at 161, citing Exh. NG-RRP-Rebuttal-1; Company Reply Brief at 56-59). National Grid contends that it routinely prepares forecasts of taxable income and estimates how much of the NOL balance is expected to be utilized against that future taxable income, and that its current forecasts show that the NOL associated with the TCJA will be fully utilized by 2027 (Company Reply Brief at 58, citing Exh. DPU 6-5 & Att.; Tr. 1, at 124-125). In particular, the Company claims that it expects to have taxable income going forward because the 2017 TCJA removed bonus depreciation that previously contributed to its negative taxable income (Company Brief at 161, citing Exh. NG-RRP-Rebuttal-1, at 5; Company Reply Brief at 58).

Additionally, National Grid disagrees with the Attorney General's argument that the Company's proposed amortization method of NOL-related excess ADIT creates intergenerational inequity (Company Reply Brief at 58). National Grid argues that while its proposal nearly offsets the annual protected excess ADIT amortization, it does not deny current customers the benefit of protected excess ADIT passback because the Company's income tax is lower by the amount of the annual protected excess ADIT amortization (Company Brief at 162-163, citing Exh. NG-RRP-Rebuttal-1, at 7; Company Reply Brief at 59). Further, National Grid asserts that it limits the NOL-related excess ADIT to the annual protected excess ADIT amortization because the NOL is primarily plant related (Company Brief at 93, 161, citing Exhs. NG-RRP-Rebuttal-1, at 5; NG-RRP-2, Sch. 10, at 5).

The Company contends that, in contrast to the Attorney General's assertion, it has offered evidence that the utilization of the NOL balance does have a bearing on amortization of the NOL-related excess ADIT (Company Reply Brief at 57). Specifically, National Grid claims that it records the NOL balance for future income tax deduction based on the Department's previous finding that the accumulated balance of excess ADIT is available to utilities to further invest until it is utilized by the utilities to fund the taxes due and payable in the later year (Company Reply Brief at 57-58, citing East Northfield Water Company, D.P.U. 19-57, at 14 (2020)). As noted above, National Grid claims that in certain years prior to the passage of the TCJA, the Company was unable to fully utilize the benefits of certain tax deductions because it had negative taxable income (Company Reply Brief at 57, citing Exh. NG-RRP-Rebuttal-1, at 4). Thus, the Company contends that it recorded NOLs that can be used to offset its tax liability in future years, and that the value of those NOLs, which partially offset the Company's ADIT, was also affected by the TCJA (Company Reply

Brief at 57-58). Therefore, National Grid asserts that a portion of the excess ADIT the Company recorded relates to those NOLs (Company Reply Brief at 58).

Finally, National Grid asserts that the comparison of the NOL-related excess ADIT amortization to its treatment of uninsured claims expense is not irrelevant (Company Reply Brief at 59). Rather, National Grid claims that the NOL-related excess ADIT is calculated using future taxable income forecasts and, as such, "other costs in the Company's proposed cost of service are similar to the Company's proposed NOL-related excess ADIT amortization" (Company Reply Brief at 59, citing Exh. NG-RRP-Rebuttal-1, at 5; Tr. 1, at 124).

D. Analysis and Findings

1. Introduction

Consistent with Department directives in docket D.P.U. 18-15, National Grid recorded a regulatory liability for the balance of protected excess ADIT resulting from the 2017 TCJA (Exh. NG-RRP-1, at 25). See D.P.U. 18-15, Order Opening Investigation at 4-5. As noted above, the Department previously accepted the Company's recorded regulatory liability and ordered National Grid to return the excess ADIT to its customers. D.P.U. 18-15-D at 17-21. National Grid also recorded a regulatory asset, i.e., NOL-related excess ADIT, to account for the tax loss the Company incurred through its NOL balance as of January 1, 2018 (Exh. DPU 6-3). The recording of the foregoing regulatory liability and regulatory asset due to tax rate changes is required by generally accepted accounting principles ("GAAP") under ASC 740, Accounting for Income Taxes (Tr. 8, at 999-1000).[93]

The Department distinguishes between plant-related and non-plant related excess ADIT or ADIT deficiencies. D.P.U. 15-155, at 257-258; D.P.U. 14-150, at 241; Bay State Gas Company, D.P.U. 13-75, at 269-270 (2014); D.P.U. 95-40, at 50. The relevant GAAP under ASC 740 requires deferred income tax assets and liabilities to be adjusted for the effect of a tax rate change. The Department has previously found that it is appropriate to recover ASC 740 regulatory assets over an amortization period reflective of the remaining life of the company's utility plant in service at the time. D.P.U. 15-155, at 257. See also D.P.U. 14-150, at 241; D.P.U. 13-75, at 269-270; D.T.E. 05-27, at 227-228 n.136; D.P.U. 95-40, at 50; Bay State Gas Company, D.P.U. 92-111, at 172-173 (1992); Essex County Gas Company, D.P.U. 87-59, at 55-56 (1987). The Company has provided no compelling reasons to depart from this precedent for plant-related items.

Further, under IRS normalization rules, reserves for protected excess ADIT must be reduced over the life of the associated plant. See Pub. L. No. 115-97, § 1561(d)(1), (2). A violation of these normalization rules could have adverse tax consequences for the public utility, including potential tax penalties under the 2017 TCJA. See Pub. L. No. 115-97, § 1561(d)(3), (4); D.P.U. 17-170, at 189 n.98.

---

93 ASC 740, formerly Statement of Financial Accounting Standard No. 109, requires companies to recognize income taxes on financial statements on asset and liability bases.

2. Review of Company Proposal

As noted above, the Company proposes to amortize the NOL-related excess ADIT over an accelerated period, which results in nearly a complete offset of excess ADIT owed to customers (Exhs. NG-RRP-1, at 92; NG-RRP-2, Sch. 10, at 5 (Rev. 3); DPU 6-5 & Att.). As an initial matter, the Department has reviewed the Company's calculation of the passback amounts of protected excess ADIT, the associated amortization periods, and the amounts of NOL-related excess ADIT (Exhs. NG-RRP-2, Sch. 10, at 5 (Rev. 3); DPU 6-5, Att.). We find that the Company accurately calculated the amounts of excess ADIT and NOL-related excess ADIT and the amortization period associated with the excess ADIT. As discussed below, however, the Department does not accept the Company's proposed amortization periods associated with the NOL-related excess ADIT.

The record shows that the Company's NOL each year is primarily due to a specific tax deduction - the repair deduction expense (Exh. DPU 55-8; RR-DPU-5; RR-DPU-44). For example, the Company had a combined net operating loss of $135,281,614 in fiscal year 2018, and a repair deduction expense of $208,446,613 (Exh. DPU 55-8; RR-DPU-5). If the Company did not recognize the repair deduction for tax purpose, the Company would have had a net operating income of $73,164,999 (Exh. DPU 55-8; Tr. 8, at 997; RR-DPU-5; RR-DPU-44). According to the Company, it changed its accounting method in 2009 so that a repair deduction is no longer part of the capitalized asset, but rather is recorded as O&M expense (Tr. 1, at 117; Tr. 8, at 982). National Grid records the repair deduction expense based on the utility plant put in service each year (RR-DPU-5; RR-DPU-44). In this regard, the record shows that for tax purposes, the Company has been taking 24 percent to 48 percent of plant cost each year since 2009 as a repair deduction expense (e.g., repair deduction divided by total plant cost each year) (RR-DPU-5; RR-DPU-44).

As noted above, under IRS normalization rules, reserves for protected excess ADIT must be reduced over the life of the associated plant. See Pub. L. No. 115-97, § 1561(d)(1), (2). Because of the Company's tax treatment of the repair deduction as an expense causing NOLs prior to 2018, the IRS normalization rule does not apply to the Company's NOL-related excess ADIT (Exh. DPU 6-3). Therefore, the Commission has discretion in determining the appropriate amortization period for this NOL-related excess ADIT. See IRS Rev. Pro. 2020-39.[94] The Company seeks to re-capitalize the repair deduction expense for ratemaking purposes so that the total plant costs are recognized in the plant investment and, therefore, qualify for rate of return (Exh. DPU 55-5; Tr. 1, at 108-109; Tr. 8, at 1001). As reasoned above, the NOL-related excess ADIT is the tax loss the Company recognized under ASC 740 as a result of the enactment of 2017 TCJA. The Company has determined all of its NOL is the result of accelerated plant deductions that included the repair deduction expense (Tr. 1, at 118). Thus, because the Company re-capitalized these costs for ratemaking purposes and consistent with the IRS classification of

94 On August 14, 2020, IRS issued Revenue Procedure 2020-39 to provide guidance on clarifying the normalization requirements on excess ADIT following the 2017 TCJA. The guidance explicitly addressed the excess ADIT related to accelerated depreciation and stated any excess ADIT unrelated to accelerated depreciation is to be determined by the regulator in a rate proceeding. IRS Rev. Pro. 2020-39, § 3.

excess ADIT, the underlying property of the NOL-related excess ADIT is the Company's plant in service. Consequently, the NOL-related excess ADIT warrants the same treatment of the excess ADIT the Department previously directed in D.P.U. 18-15-D at 18-19, including matching amortization periods.

In this regard, the Department is not persuaded that our decision in D.P.U. 19-57 supports the Company's position that the utilization of the NOLs has a bearing on the amortization of the NOL-related excess ADIT balance (Company Reply Brief at 57-58, citing D.P.U. 19-57, at 14). As the Company points out, the Department has found that the accumulated balance of ADIT is available to a company to further invest until it is then utilized by the company to fund the taxes due and payable in the later years. D.P.U. 19-57, at 14. See also D.P.U. 87-59, at 63; AT&T Communications of New England, D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983); Boston Edison Company, D.P.U. 18200, at 33-34 (1975). This principle, however, applies to ADIT, not excess ADIT. Excess ADIT represents a portion of ADIT that the utility no longer owes to the IRS as a result of changes in income tax rates, such as those resulting from the 2017 TCJA and the Tax Reform Act of 1986. The Department has previously directed utilities to promptly adjust rates and return the excess ADIT to ratepayers so that the ratepayers receive the benefits from the decrease of federal corporate income tax rate. D.P.U. 18-15 Order Opening Investigation at 4-6; Investigation Into Effect of the Reduction in Federal Income Tax Rates on Utility Rates as a Result of the Tax Reform Act of 1986, D.P.U. 87-21-A at 22 (1987). Thus, our decision in D.P.U. 19-57 has no bearing on the issues presented in this matter.

Additionally, in support of the proposed NOL-related excess ADIT based on NOL balance utilization, National Grid stated that it expects to have net operating income because the 2017 TCJA removed certain tax deductions, including bonus depreciation, that the Company states contributed to its negative taxable income (Exh. NG-RRP-Rebuttal-1, at 5; Tr. 8, at 1005). Contrary to National Grid's assertion, however, the record shows that the Company is still eligible to take bonus depreciation as long as any of the plant put in service after 2018 contains plant costs that were incurred before the 2017 TCJA (Tr. 8, at 1006-1007; RR-DPU-5; RR-DPU-44). According to the Company, the first expense and final expense associated with the plant asset could be years apart (Tr. 8, at 1007). The Department notes that the bonus depreciation is in addition to the repair deduction expense mentioned above (RR-DPU-5; RR-DPU-44). Moreover, National Grid stated its NOL is primarily associated with accelerated depreciation and repair deduction expense, and the Company confirmed that it will continue to take this repair deduction expense in the future (Tr. 1, at 114; Tr. 8, at 982-983). Therefore, the Department is not persuaded that the Company has shown it is likely to have net operating income going forward.

Further, we find National Grid's comparison of the NOL-related excess ADIT amortization to uninsured claim expense or other costs in the proposed cost of service to be irrelevant. The Company's uninsured claims expense is determined separately based on the Department's long-standing principles regarding the establishment of representative level of costs (see Section VIII.G.3 below). Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 106 (2014); D.P.U. 10-55, at 272; D.P.U. 09-30, at 219-220; Massachusetts Electric Company, D.P.U. 89-194/195, at 73-75 (1990). On the other hand, the calculation of the amortization period applicable to the Company's NOL-related excess ADIT is not intended to set a representative level of costs, but rather to set an appropriate offset to the amount of plant-related excess ADIT to be returned to customers, as discussed above.

Finally, the Department recognizes that in D.P.U. 18-150, we allowed Massachusetts Electric Company and Nantucket Electric Company to amortize NOL-related excess ADIT over a shorter time frame than the accompanying excess ADIT. D.P.U. 18-150, at 196. In that proceeding, however, there was no convincing evidence that the electric distribution companies would be taking future repair deductions and, therefore, would not have net operating income. The Department typically determines amortization periods based on a case-by-case review of the evidence and underlying facts. D.P.U. 08-27, at 99; Barnstable Water Company, D.P.U. 93-223-B at 14 (1994); D.P.U. 84-145-A at 54. The circumstances in the instant case appear to be different than those presented in D.P.U. 18-150. As such, and based on the considerations and finding above, we conclude that a different result is warranted for Boston Gas and the former Colonial Gas.

3. Conclusion

Based on the foregoing considerations and findings, we direct the Company to amortize its NOL-related excess ADIT on the same schedule as its protected excess ADIT amortizations, i.e., 52.5 years for Boston Gas and 39.3 years for the former Colonial Gas.[95] This finding results in an annual NOL-related excess ADIT amortization amount of $471,273 for Boston Gas and $110,933 for the former Colonial Gas. Accordingly, the Department will reduce the Company's proposed cost of service by $2,656,270.[96] The effect of this adjustment is shown in Schedule 8 below.

VIII. OPERATION AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. D.P.U. 96-50 (Phase I) at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). This approach recognizes that the different components of compensation (e.g., wages and benefits) are to some extent substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a

---

95 The years of amortization are calculated by taking the balance of protected excess ADIT as of September 30, 2021, divided by the annual protected excess ADIT amortization amount for each legacy company (Exh. NG-RRP-2, Sch. 10, at 5 (Rev. 3)).

96 The adjustment is calculated by subtracting the approved annual NOL-related excess ADIT amount of $582,206 (i.e., $471,273 + $110,933) from the proposed combined annual NOL-related excess ADIT amortization amount for both companies of $3,238,476.

manner supported by its overall business strategies. D.P.U. 92-250, at 55. The individual components of a company's employment compensation package, however, will be appropriately left to the discretion of a company's management. D.P.U. 92-250, at 55-56.

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

National Grid's employee compensation program is known as the "Total Rewards Program" (Exh. NG-MPH-1, at 5). The Total Rewards Program encompasses base pay, variable pay, medical and dental insurances, life and long-term disability insurances, vacation and holiday pay, a pension plan, a 401(k) plan, and other post-retirement benefits (Exh. NG-MPH-1, at 6). The Company also provides tuition assistance, childcare assistance, and physical therapy to its employees (Exhs. NG-MPH-1, at 28-29; DPU 49-6).

2. Post-Test-Year Full-Time Employees

a. Introduction

At the end of the test year, i.e., March 31, 2020, the Company had 45 direct management employees and 1,292 direct union employees, for a total of 1,337 employees (Exh. AG 1-44, Att. 1, at 3). In addition to these direct employees, NGSC had

5,380 management employees and 1,346.5 union employees, for a total of 6,726.5 employees (Exh. AG 1-44, Att. 1, at 3).

The Company states that it plans to hire 209 post-test-year full-time equivalents ("FTEs") to support its gas safety and compliance work plans (Exh. NG-GSC-1, at 38). More specifically, the additional staffing would be hired as follows: (1) 39 FTEs to address recommendations made in the Dynamic Risk Report and to meet PHMSA requirements; (2) 21 FTEs to replace contractors with in-house resources for damage prevention;[97] and (3) 149 field operations and customer meter service ("CMS") FTEs to perform compliance work to meet evolving safety and reliability requirements in Massachusetts (Exhs. NG-GSC-1, at 15-44; DPU 16-1; DPU 18-8). The 209 FTEs comprise 195 FTEs for the Company and 14 FTEs for NGSC (Exhs. NG-GSC-1, at 38; NG-RRP-2, Sch. 31, at 4-6 (Rev. 3)).

National Grid initially proposed to include $18,620,631 in its cost of service for all 209 post-test-year FTEs (Exhs. NG-RPP-1, at 73; NG-RRP-2, Sch. 31, at 3-6; NG-RRP-5, at 3). During the proceedings the Company revised this amount and now proposes to include $12,102,499 in its cost of service, which is comprised of: (1) $7,410,346 for payroll expense; (2) $1,771,111 for health care expense; (3) $43,140 for group life insurance expense; (4) $270,466 for 401(k) expense; (5) $1,186,784 for payroll taxes, (6) $252,602 for

97 The Company notes that its proposed cost of service includes $1,260,762 in contractor costs that should be removed if the Department approves the costs associated with the post-test-year damage prevention hires (Exhs. NG-GSC-1, at 39; DPU 18-5; AG 51-10).

employee expenses; and (7) $1,168,051 for transportation expense (Exhs. NG-RRP-2, Sch. 31, at 3-6 (Rev. 3); NG-RRP-5, at 3 (Rev. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that any adjustment associated with post-test-year FTEs should be limited to the 133 net incremental employees that the Company actually hired as of March 31, 2021, because any subsequent adjustment is not known and measurable and is speculative (Attorney General Brief at 121-122, citing Exh. NG-RRP-2, Sch. 31, at 4 (Rev. 1); Attorney General Reply Brief at 72). In this regard, the Attorney General rejects any notion that the Department held the record open to the date of the Company's reply brief for the purpose of allowing the Company to update the number of actual incremental hires (Attorney General Reply Brief at 72, citing Company Brief at 181; Tr. 13, at 1330).[98]

[98] On August 5, 2021, the Attorney General filed a motion to strike ("Motion to Strike") certain information regarding additional post-test-year FTEs provided by the Company with its July 28, 2021, final cost of service update and its reply brief (Motion to Strike at 1, 6-7). The Attorney General argued that the record was not held open to allow for the Company's additional filings and that the Company failed to move to reopen the record or support the filing with an appropriate affidavit (Motion to Strike at 6-7). On August 12, 2021, the Company filed a reply to the Motion to Strike ("Company Reply"). Among other things, National Grid argued that the additional post-test-year FTE information provided on July 28, 2021, was proposed by the Company and requested by the Department, and that the Attorney General did not object to this update until the end of evidentiary hearings in this matter (Company Reply at 2, 5-6). The Company also maintained that the Department left the record open to accommodate the July 28, 2021, update (Company Reply at 6-7). On August 20, 2021, the Attorney General filed a motion for leave to file reply comments and a set of reply comments. On August 27, 2021, the Company filed a response to the Attorney General's August 20, 2021, filings.

The Attorney General also asserts that the average salary per employee for the post-test-year FTEs is significantly less than the salary per existing employee, and a portion of the payroll taxes are based on a percentage of salaries (Attorney General Brief at 123, citing Exh. AG-DJE-Surrebutal-1, at 7). Therefore, the Attorney General argues that if the Department allows an adjustment for post-test-year FTEs, the Department should calculate the associated payroll and FICA taxes based on the actual salaries of the 133 incremental FTEs (Attorney General Brief at 122-123, citing Exhs. AG-DJE-Surrebuttal-1, at 7; DJE-1S, Sch. 5; Attorney General Reply Brief at 71-72). Specifically, the Attorney General asserts that the payroll tax adjustment must be reduced by $170,533 to recognize the lower salary per post-test-year FTE (Attorney General Brief at 123, citing Exh. AG-DJE-Surrebuttal-1, at 7).[99] The Attorney General notes that after this modification, the adjustment to recognize the 133 net incremental FTEs hired through March 31, 2021, is $7,237,060 (Attorney General Brief at 123, citing Exhs. AG-DJE-Surrebutal-1, at 7; DJE-1S, Sch. 5).

ii. Company

National Grid argues that its proposed adjustment to recognize post-test-year FTEs would be known and measurable by the close of the record, which the Company contends was July 28, 2021 (Company Brief at 61-62). National Grid maintains that it could not hire

99 On brief, the Attorney General notes that the Company's proposal also includes health care expense, group life insurance expense, 401(k) expense, employee expenses, and transportation expense related to the post-test-year FTEs (Attorney General Brief at 121, citing Exh. NG-RRP-1, at 73-74; see also Exh. NG-RRP-2, Sch. 31, at 4 (Rev. 3)).

all 209 proposed FTEs prior to the end of the test year because a union strike forced the Company to prioritize its workload to focus on completing work with the highest safety risks (Company Brief at 133, citing Exh. NG-GSC-1, at 43). Further, National Grid notes that after the strike ended, the Company's main focus shifted to completing overdue work and keeping current with other compliance obligations (Company Brief at 133-134, citing Exh. NG-GSC-1, at 43). In addition, the Company asserts that the COVID-19 pandemic delayed a significant amount of work and impacted the Company's timeline for hiring these new employees (Company Brief at 134, citing Exh. NG-GSC-Rebuttal-1, at 7-8; AG 37-14).

National Grid argues that despite the delays as of March 31, 2021, the Company had hired a total of 133 of the proposed 209 post-test-year FTEs (Company Brief at 135, citing Exh. NG-GSC-Rebuttal-1, at 8). The Company, however, notes that it proposed to update the number of hires through the close of the record and that the Attorney General did not object to this proposal in her surrebuttal testimony or during evidentiary hearings (Company Reply Brief at 62). Thus, the Company contends that the Department should accept the final number of FTEs hired as of July 28, 2021 (Company Brief at 181; Company Reply Brief at 61-62, citing Exhs. NG-GSC-Rebuttal-1, at 9; DPU 16-6 (Supp.); Tr. 1, at 146; Tr. 13, at 1330, 1334).

National Grid asserts that the hiring of additional employees is outside of the Company's ebb and flow of its workforce (Company Brief at 177-178; Company Reply Brief at 60-61). The Company states that the post-test-year FTEs were not hired to fill vacancies due to retirements, resignations, terminations or transfers, but rather represent new staffing positions to address increased gas safety and compliance work resulting from the Merrimack Valley incident (Company Brief at 178, citing Exhs. NG-GSC-1, at 38; NG-GSC-Rebuttal-1, at 4, 5-6; DPU 16-10; Company Reply Brief at 60-61). Further, the Company notes that the Department recently recognized that the Merrimack Valley incident had a direct and profound impact on the gas distribution industry, and the hiring of additional staff to address the resulting in increase in compliance and safety work warranted a departure from the traditional ebb and flow standard (Company Brief at 178, citing D.P.U. 19-120, at 241; Company Reply Brief at 60).

Regarding salaries, the Company claims that the average salary per employee for the post-test-year FTE is less than the salary per existing employee because these new safety and compliance employees are being hired into entry-level positions, allowing other personnel to progress into higher-level positions, all of which are directly related to completing compliance-related work (Company Brief at 179-180, citing Exhs. NG-GSC-1, at 42; NG-GSC-Rebuttal-1, at 7; DPU 16-9; DPU 16-9, Att.; DPU 31-2; AG 16-1; AG 37-8; AG 37-11).

The Company additionally points out that the payroll tax adjustment does not need to be modified to recognize the lower salary per incremental employee (Company Brief at 180; Company Reply Brief at 61). The Company claims that it calculated payroll tax by projecting each employee's salary and wages at the end of the rate year to estimate what percent of payroll is subject to each tax increase cap (Company Brief at 180, citing Exh. NG-RRP-1, at 83; Company Reply Brief at 61). National Grid argues this is a representative amount based on the average cost per employee and it does not consider increases in payroll or other factors that may cause an increase in payroll tax (Company Brief at 180, citing Tr. 8, at 948; Company Reply Brief at 61). Further, National Grid claims that this practice is consistent with how the Company calculates other employee overheads, such as health care (Company Reply Brief at 61, citing Tr. 8, at 948). National Grid, therefore, concludes the Company's calculated payroll tax for both the current employees and the new hires is appropriate to be included in the cost of service, as there is no one-for-one replacement due to the hiring of the incremental employees (Company Brief at 180; Company Reply Brief at 61).

c. Analysis and Findings

The Department has recognized that employee levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. Massachusetts-American Water Company, D.P.U. 88-172, at 12 (1989); D.P.U. 1270/1414, at 16-17. In recognition of this variability, the Department generally determines payroll expense on the basis of test-year employee levels, unless there has been a significant post-test-year change in the number of employees that falls outside the normal ebb and flow of a company's workforce. The Berkshire Gas Company, D.P.U. 90-121, at 80-81 (1990); D.P.U. 88-172, at 12.

The Department first considers whether the Company has demonstrated that the costs related to the post-test-year FTEs are known and measurable. D.P.U. 17-170, at 79. As of the close of the record on this issue, the Company had hired 133 of the 209 post-test-year

FTEs (Exhs. NG-RRP-2, Sch. 31, at 4-6 (Rev. 2); DPU 16-6 (Supp.)).[100] Further, the Company provided the costs associated with these hires (Exhs. NG-RRP-2, Sch. 31, at 4-6 (Rev. 2); DPU 16-6, Att. (Supp.)). As such, the Department finds that the costs associated with these 133 FTEs are known and measurable. The Company has not demonstrated that the remaining 76 FTEs were hired prior to the close of the record.[101] Therefore, the costs for the remaining 76 FTEs are not known and measurable and, as such, we will not consider them for recovery in the Company's cost of service.

Next, we consider whether the 133 post-test-year FTEs whose costs we found to be known and measurable fall outside the normal ebb and flow of the Company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12. In this regard, the Company argues that the proposed post-test-year FTEs would not be hired to fill vacancies due to retirements, resignations, terminations or transfers, but rather represent new staffing positions to address

---

[100] For purposes of this issue, the Department considers the record closed as of May 28, 2021, when the Company provided an updated cost of service following evidentiary hearings (see Tr. 13, at 1328-1329). The Department typically holds open the record to the date of the Company's reply brief for verifiable, non-controversial evidence, such as a utility's most recent property tax bills issued by cities and towns. See, e.g., D.P.U. 17-170, at 173; D.P.U. 17-05, at 250; D.P.U. 15-155, at 213; D.P.U. 14-150, at 209; D.P.U. 88-67 (Phase I) at 165-166; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). In light of this decision, we need not reach the merits of the Attorney General's Motion to Strike (see n.98 above).

[101] On brief, the Company argues that the Department should accept the number of FTEs hired as of July 28, 2021, the date upon which the Company filed its reply brief and final revenue requirement update (Company Brief at 181; Company Reply Brief at 61-62, citing Exhs. NG-GSC-Rebuttal-1, at 9; DPU 16-6 (Supp.); Tr. 1, at 146; Tr. 13, at 1330, 1334). That number appears to be 160 FTEs (Exhs. NG-RRP-2, Sch. 31, at 4-6; DPU 16-6 (Supp.)).

increased gas safety and compliance work resulting from the Merrimack Valley incident (Company Brief at 178, citing Exhs. NG-GSC-1, at 38; NG-GSC-Rebuttal-1, at 4, 5-6; DPU 16-10; AG 52-5 & Att.; Company Reply Brief at 60-61). Thus, the Company argues that these employees fall outside of the normal ebb and flow of the Company's workforce (Company Brief at 178, citing Exhs. NG-GSC-1, at 38; NG-GSC-Rebuttal-1, at 4, 5-6; DPU 16-10; Company Reply Brief at 60-61).

The Department is not persuaded by the Company's arguments. Rather, consistent with past practice, we will measure the proposed post-test-year increase in employee count against the complement of test-year-end National Grid and NGSC employees. See, e.g., D.P.U. 19-120, at 240; D.P.U. 17-170, at 80 & n.51.[102] At the end of the test year, there were 1,337 National Grid FTEs and 6,726.5 NGSC FTEs for a total of 8,063.5 employees (Exh. AG 1-44). When comparing the 133 FTEs to the test-year-end total employee count for National Grid and NGSC of 8,063.5 FTEs, the increase is less than two percent. As a result, the impact of 133 FTEs is not a significant change for National Grid.[103] The Department finds that neither the number of proposed FTEs nor the percentage

---

[102] The Department notes that in D.P.U. 17-170-B at 20, National Grid requested reconsideration of the Department's decision that the hiring of 69 post-test-year FTEs was not a significant change in the Company's workforce. The Department found no reason to reconsider the basis of its decision. D.P.U. 17-170-B at 22-24.

[103] Our decision would not be different if we considered either 160 post-test-year FTEs or all 209 positions instead of the 133 post-test-year FTEs whose costs we found to be known and measurable.

change in employee levels is outside the normal ebb and flow of hirings, retirements, resignations, or departures.

Typically, our analysis would end here with a denial of the Company's requested post-test-year adjustment. We note, however, that the Department has allowed for a departure from our typical standard to consider cost recovery related to post-test-year positions created to support increased field work associated with maintaining the safety and integrity of the distribution system and responding to increasing regulatory requirements following the Merrimack Valley incident. See D.P.U. 19-120, at 241. In particular, we have recognized that the Merrimack Valley incident had a direct and profound impact on the gas distribution industry and highlighted the need for additional protections on the low-pressure gas distribution systems, as confirmed in the Dynamic Risk Report. D.P.U. 19-120, at 241. Based on the record before us, we find that the Company has provided convincing evidence that the 133 FTE positions were created as part of its enhanced gas safety and compliance efforts to address increased field work and regulatory compliance requirements arising from the Merrimack Valley incident (Exhs. NG-GSC-1, at 15-38; NG-GSC-5; DPU 16-1; DPU 16-9, Att.; DPU 18-3; DPU 18-4; DPU 18-7; DPU 18-9; AG 20-14; AG 20-10; AG 23-6; AG 23-9). Thus, we will allow the Company to recover the costs associated with these post-test-year FTEs. D.P.U. 19-120, at 241-243. Further, we find that the Company has provided a representative level of costs for the 133 post-test-year employees, and, therefore, we need not adjust payroll and FICA taxes as recommended by the Attorney General (Exhs. NG-RRP-2, Sch. 31, at 4-6 (Rev. 2); AG-DJE-Surrebuttal-1, at 6-7; DJE-1S, Sch. 5; Tr. 8, at 947-948; Attorney General Brief at 122-123; Attorney General Reply Brief at 71-72). Finally, the Department will remove from the Company's cost of service contractor costs associated with the damage prevention post-test-year FTEs (Exhs. NG-GSC-1, at 39; DPU 18-5; AG 51-10; see also n.97 above).[104]

As noted above, the Company's proposed cost of service includes $12,102,499 in costs associated with 209 post-test-year FTEs (Exhs. NG-RRP-2, Sch. 31, at 3-6 (Rev. 3); NG-RRP-5, at 3 (Rev. 3)). Based on the above considerations and findings, the Department approves the costs associated with 133 post-test-year FTEs, which amounts to $7,407,596 (see Exh. NG-RRP-2, Sch. 31, at 3-6 (Rev. 2)). Further, the Department removes from the proposed cost of service $1,260,762 in contractor costs (Exhs. NG-GSC-1, at 39; DPU 18-5). Accordingly, we reduce the Company's proposed cost of service by a total of $5,955,665 ($4,694,903 + $1,260,762), as shown in Schedule 2 below.[105]

---

104 As a result of the removal of contractor costs, inflation expense will be updated in Schedule 2A below.

105 The Company presented the costs associated with the proposed post-test-year FTEs as a standalone schedule in its proposed cost of service (Exh. NG-RRP-2, Sch. 31 (Rev. 3)). The total costs include payroll expense, health care expense, group life insurance expense, 401(k) expense, payroll taxes, employee expenses, and transportation expense (Exhs. NG-RRP-2, Sch. 31, at 4-6 (Rev. 3)). Therefore, the Department need not make any further adjustment to the Company's proposed cost of service beyond the disallowances discussed above.

3. Union Wages

a. Introduction

During the test year, National Grid booked $99,791,505 in payroll expenses for union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). Of these expenses, $85,207,701 was directly incurred, $12,217,403 was allocated from NGSC, and $2,366,401 was allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)).

National Grid proposes to increase its union payroll expense based on the following: (1) United Steelworkers of America, Locals 12003 and 12012-4 union wage increases of 2.75 percent effective June 22, 2020, and three percent effective June 21, 2021; (2) United Steelworkers of America Local 13507 union wage increases of 2.75 percent effective June 8, 2020, and 2.75 percent on June 7, 2021; (3) Utility Workers Union of America, Local 318 union wage increase of 2.5 percent effective April 27, 2020, and a three percent increase on April 26, 2021; and (4) Utility Workers Union of America, Locals 350 and 369 wage increase of 2.5 percent effective June 2, 2020, and three percent effective June 2, 2021 (Exhs. NG-MPH-1, at 14-15; AG 1-42, Atts. 1-11).

National Grid proposes adjustments to increase the Company's test-year union payroll expense to account for the aforementioned wage increases included in the collective bargaining agreements (Exhs. NG-MPH-1, at 14-15; AG 1-42, Atts. 1-11). Accordingly, the Company increased its test-year union payroll expense by $6,475,360, attributable as follows:

(1) \$4,934,464 in direct costs; (2) \$1,410,292 allocated from NGSC; and (3) \$130,604 from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)).

b. Positions of the Parties

National Grid claims that union wage rates are set through the collective bargaining process, involving negotiations between the Company and the collective bargaining units to establish wages, benefits, and conditions of employment (Company Brief at 168, citing Exh. NG-MPH-1, at 13). The Company indicates that National Grid's union payroll included in its revenue requirement include wage increases through April 1, 2022, which are already committed to union employees by virtue of the currently effective collective bargaining contracts (Company Brief at 168, citing Exh. NG-MPH-1, at 14).

The Company argues that, to determine whether such rates are competitive with the market, the Company has performed an analysis of hourly union wages compared to the hourly pay rate from surrounding utilities (Company Brief at 169, citing Exh. NG-MPH-8). National Grid asserts that the analysis shows that the hourly rates paid to National Grid union employees are within the range of these other utilities (Company Brief at 169, citing Exh. NG-MPH-9). As a result, the Company claims to have demonstrated that the union wage levels included in the revenue requirement calculation are reasonable (Company Brief at 169). No intervenor addressed this matter on brief.

c. Analysis and Findings

The Department's standard for post-test-year union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the effective date of new base distribution rates; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Company's proposed adjustments only relate to increases that have been granted before April 1, 2022, the midpoint of the first twelve months after the Department's Order in this proceeding, including the union payroll increases that occurred in 2020 and 2021 based on signed collective bargaining agreements between the Company and the respective unions (Exhs. NG-MPH-1, at 3; NG-RRP-2, Sch. 12, at 4-9 (Rev. 3); AG 1-42, Atts. 1-11). Thus, we find that the proposed union wage increases are known and measurable.

Further, with respect to the reasonableness of the union wage increases, the Company submitted a comparison of its average union wages with other employers in the Northeast (Exh. NG-MPH-8). The documentation provided demonstrates that hourly rates paid to the Company's union employees are comparable to the median hourly rates other employers in the region pay for the selected union job titles (Exh. NG-MPH-8). Thus, we find that the Company has demonstrated the reasonableness of the union wage increases.

Based on the above, the Department finds that National Grid has demonstrated the following: (1) the union salary increases are scheduled to become effective no later than six months after the Department's Order; (2) there is sufficient documentation granting union wage increases that are scheduled to occur after the date of this Order; and (3) the union wage increases are reasonable. Accordingly, we allow the Company's adjusted union payroll expense.

4. Non-Union Wages

a. Introduction

During the test year, National Grid booked $49,623,875 in payroll expenses for non-union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). Of these expenses, $2,689,056 was directly incurred, $46,332,168 was allocated from NGSC, and $602,651 was allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)).

The Company proposes to increase its non-union payroll expense by $4,097,017 to account for increases that were effective July 1, 2020, in addition to raises effective July 1, 2021, thus, after the end of the test year (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). The payroll expense increase is attributable as follows: (1) $263,690 in direct costs; (2) $3,816,755 from NGSC; and (3) $16,572 allocated from all other companies (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)).

The Company tested the competitiveness and reasonableness of its non-union base salaries and total compensation levels against external market trends for energy/utility companies and general industry sectors using studies performed by Willis Towers Watson (Exh. NG-MPH-2). In addition, the Company provided a historical comparison of non-union base wage increases to union base wage increases (Exhs. NG-MPH-7; AG 1-41).

b. Positions of the Parties

National Grid claims that, in setting compensation and benefit levels for the Company, human resources' current business strategy is focused on developing and delivering a market competitive compensation and benefit package that is reasonable, recognizes and rewards excellence, maintains fair and competitive market pay and benefits for employees, and encourages employees to improve skills while balancing the interests of customers with respect to cost containment (Company Brief at 166, citing Exh. NG-MPH-1, at 5).

National Grid adds that the Company aims to set pay at the median level of the marketplace (Company Brief at 167, citing Exh. NG-MPH-1, at 9). To determine median pay level for non-union employees, the Company benchmarks certain positions within each salary band and compares overall pay for the benchmarks to the 50th percentile of overall pay for comparable jobs in similarly sized companies based on market surveys (Company Brief at 167, citing Exh. NG-MPH-1, at 9). National Grid states that pay increases are awarded based on individual employee performance and a comparison to the 50th percentile of the marketplace, in addition to promotions, increased job responsibilities, or increased skills and competencies (Company Brief at 167, citing Exh. NG-MPH-1, at 8). Any base pay increases for the Company's non-union employees generally go into effect on July 1 of each year (Company Brief at 167, citing Exh. NG-MPH-1, at 8).

The Company points out that because of the economic impacts of COVID-19 on National Grid's customers and the communities it serves, senior management lowered the non-union wage increase that had been previously approved from 3.25 percent to

1.91 percent (Company Brief at 168, citing Exh. NG-MPH-1, at 10). Based on the above considerations, National Grid claims that these salary increases are reasonable and should be approved by the Department for inclusion in the Company's cost of service (Company Brief at 168). No intervenor addressed this issue on brief.

c. Analysis and Findings

The Department's well-established standard for post-test-year non-union payroll adjustments requires a company to demonstrate the following: (1) the non-union salary increase is scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, there is an express commitment by management to grant the increase; (3) there is a historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Boston Edison Company, D.P.U. 85-266-A/85-271-A at 107 (1986); D.P.U. 1270/1414, at 14.

The Company's proposed increase to non-union wage expense is based on payroll increases that occurred before the issuance of the Department's Order: one on July 1, 2020, and the other on July 1, 2021 (Exh. NG-RRP-2; Sch. 12, at 4-9 (Rev. 3)). The Company provided confirmation of the 2021 increase in the form of a management commitment letter stating that a three percent payroll increase for non-union employees will take place on or before July 1, 2021 (RR-DPU-1, Att.). Based on this information, the Department finds that the non-union salary increases are scheduled to become effective prior to issuance of our Order and that there is a commitment by management to grant the 2021 increase.

In addition, National Grid provided a historical correlation of non-union and union wage increases and demonstrated that it awarded non-union and union pay increases every year since 2016 (Exh. AG 1-41, Att.). Between 2016 and 2020, National Grid granted union wage increases between zero percent and three percent, and non-union wage increases between 1.91 percent and 3.64 percent (Exh. AG 1-41, Att.). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A, at 18 (1988).

With respect to the reasonableness of the non-union wages, the Company tests the competitiveness of its base salaries and total cash compensation levels against the external market on an ongoing basis. National Grid annually reviews its salary adjustments and total compensation, both current and projected, against external market trends (Exh. NG-MPH-1, at 11). Specifically, the Company aims to set pay at the median level of the marketplace (Exh. NG-MPH-1, at 9). To determine the median pay level for non-union employees, National Grid benchmarks certain positions within each salary band and compares overall pay for these positions to the 50th percentile of overall pay for comparable jobs in similarly sized companies based on market surveys (Exh. NG-MPG-1, at 9). This comparison showed that for National Grid, non-union salary and total compensation are one percent above market median (Exh. NG-MPH-2, at 5). The Department finds that the Company has demonstrated that its total proposed compensation is competitive with the market median and, therefore, reasonable (Exh. NG-MPH-2, at 5).

Based on the above, the Department finds that National Grid has demonstrated the following: (1) that non-union salary increases are scheduled to become effective no later than six months after the date of the Department's Order; (2) that there is an express management commitment to grant a three percent non-union wage increase that is scheduled to occur in July 2021, prior to the date of this Order; (3) that there is a historical correlation between union and non-union payroll increases; and (4) that the non-union wage increases are reasonable. Accordingly, we allow the Company's adjusted non-union payroll expense.

5. Incentive Compensation

a. Introduction

National Grid's incentive compensation program is known as the annual performance plan ("Performance Plan") (Exh. NG-MPH-1, at 17). The corporate objectives in the Performance Plan are linked directly to its U.S. business strategy, which is focused on delivering clean and reliable energy affordably (Exh. NG-MPH-1, at 18). Incentive compensation under the Performance Plan is determined following the close of each fiscal year but is based on award levels that are set at the beginning of the fiscal year and are tied to specified corporate and individual objectives for the performance year (Exh. NG-MPH-1, at 8). Results are calculated in April and May, with compensation payouts made by mid-June (Exhs. NG-MPH-1, at 8; NG-MPH-4, at 3; NG-MPH-5, at 3).

For Band A and Band B employees, which consists of top officers, vice presidents and senior vice presidents, 40 percent of incentive compensation is based on individual performance, while the remaining 60 percent is based on financial performance

(Exhs. NG-MPH-1, at 18; NG-MPH-4). National Grid did not include in its proposed revenue requirement the variable component for Band A and Band B employees that is tied to the achievement of financial metrics (Exhs. NG-MPH-1, at 19; NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). For Band C through Band F employees, which consists of general administrative staff, supervisors, managers, and directors, 50 percent of incentive compensation is based on corporate objectives, and 50 percent of incentive compensation is based on individual objectives (Exhs. NG-MPH-1, at 18; NG-MPH-5). For union employees, the performance measures are tied solely to the achievement of the corporate objectives that will foster the enhancement of the Company's connection with its customers and stakeholders, delivering energy efficiently with greater safety and reliability, and investing in infrastructure and networks across the U.S. footprint (Exh. NG-MPH-1, at 20).

During the test year, the Company booked $4,662,882 in incentive compensation for non-union employees, attributable as follows: (1) $254,568 in direct costs; and (2) $4,351,891 allocated from NGSC; and (3) $56,423 attributed to all other affiliates (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). Because the Company awarded incentive compensation payouts above the target level during the test year, it first reduced the revenue requirement to include only the amount of incentive compensation at target levels (Exh. NG-RRP-1, at 33). Further, the Company normalized incentive compensation because the variable pay of Boston Gas and the former Colonial Gas was understated in the test year due to an over-accrual of variable pay during fiscal year 2019 (Exh. NG-RRP-1, at 33). As a result of this prior year over-accrual, the Company did not accrue a full year of variable pay costs in fiscal year 2020 (Exh. NG-RRP-1, at 33). Therefore, National Grid proposes an increase of $231,745 to the non-union incentive compensation based on targeted results for the test year and escalating incentive compensation expenses based on post-test-year wage increases, resulting in a proposed incentive compensation expense for non-union employees of $4,894,627 (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)).

During the test year, the Company booked $1,835,987 in incentive compensation for union employees, attributable as follows: (1) $1,514,439 in direct costs; (2) $267,618 allocated from NGSC; and (3) $53,930 allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). For union employees, National Grid proposes an increase of $97,291 to the incentive compensation, based on targeted results for the test year and escalating incentive compensation expenses based on post-test-year wage increases, resulting in a compensation expense for union employees of $1,933,278 (Exh. NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)).

b. Positions of the Parties

The Company maintains that, for both its union and non-union employees, the Performance Plan is based on the individual performance of the employee and ensures that, at all times, all safety, health, and environmental requirements are adhered to and standards of customer service are achieved (Company Brief at 169-170, citing Exh. NG-MPH-1, at 17). At the same time, National Grid claims that the corporate objectives of the Performance Plan are linked to its U.S. business strategy and are built around four strategic priorities: (1) enabling the energy transition for all customers; (2) delivering for customers efficiently;

(3) growing organizational capability; and (4) empowering employees to achieve great performance (Company Brief at 170, citing Exh. NG-MPH-1, at 18).

National Grid argues that using this approach, the employee's pay is aligned with the health and performance of the Company and the achievement of established performance standards that directly benefit customers (Company Brief at 171, citing Exh. NG-MPH-1, at 20). In addition, the Company maintains that the revenue requirement does not include the variable pay component for National Grid's Band A or Band B officers that is tied to the achievement of financial metrics (Company Brief at 171, citing Exh. NG-MPH-1, at 19).

Further, National Grid argues that incentive compensation is a necessary mechanism for the Company to remain competitive in the labor market (Company Brief at 171). According to National Grid, a survey by the Willis Towers Watson Energy Services Survey Report demonstrates that nearly 100 percent of the surveyed companies have a variable pay plan program in place and more than 95 percent of employees at those companies participate in those plans (Company Brief at 171, citing Exhs. NG-MPH-1, at 16-17; NG-MPH-3; NG-MPH-9).

Based on the above considerations, the Company argues that is has demonstrated that the use of Performance Plan program is reasonable and works to the benefit of customers (Company Brief at 171). No intervenor addressed this issue on brief.

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if (1) the amounts are reasonable and (2) the incentive plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; D.P.U. 89-194/195, at 34. For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99.

First, the Department must determine whether the costs associated with the Performance Plan are reasonable in amount. The Company awarded incentive compensation payouts above the target level during the test year (Exh. NG-RRP-1, at 33). In addition, National Grid made further adjustments to account for the fact that the variable pay of Boston Gas and the former Colonial Gas was understated in the test year due to an over-accrual of variable pay during fiscal year 2019 (Exhs. NG-RRP-1, at 33; NG-RRP-2, Sch. 12, at 3 (Rev. 3)). Based on our review of this evidence, the Department finds that National Grid has demonstrated that the amount of its incentive compensation costs is reasonable. See D.P.U. 17-170, at 95; D.P.U. 10-70, at 103; D.P.U. 09-39, at 140.

Second, the Department must determine whether the Company's Performance Plan is reasonably designed to encourage good employee performance. The record shows that National Grid's Performance Plan for its Band A and Band B non-union employees is based on overall financial objectives and individual objectives (Exhs. NG-MPH-1, at 18; NG-MPH-4, at 1). National Grid has not sought to recover the variable pay component that is tied to the achievement of financial metrics[106] for Band A and Band B employees (Exhs. NG-MPH-1, at 19; NG-RRP-2, Sch. 12, at 4-9 (Rev. 3)). Individual performance for Band A and Band B employees is determined and evaluated by each employee's supervisor (Exh. NG-MPH-4, at 2). Incentive payment for employees falling within Bands C through F is based instead on U.S. focus measures (energy transition, customers, growing organizational capabilities, and people) and individual performance (Exhs. NG-MPH-1, at 18; NG-MPH-5). Thus, the Performance Plan encourages good employee performance directly by rewarding non-union employees for achieving personal goals and by contributing to the financial success of National Grid (Exhs. NG-MPH-1, at 16; NG-MPH-4; NG-MPH-5). Further, National Grid ensures that its employees are committed to meeting customer needs by establishing performance goals that are based on providing safe, reliable, and efficient services to customers (Exhs. NG-MPH-1, at 16; NG-MPH-4; NG-MPH-5). Moreover, National Grid has provided comprehensive analyses of base salaries and target total compensation compared to the market (Exh. NG-MPH-2). The Department finds, based on the results of these studies and the foregoing considerations, that National Grid has demonstrated that the Performance Plan is reasonably designed to encourage good employee performance.

---

106 Incentive payment related to overall financial objects for the employee in Band A and Band B is based on the employee's performance against pre-determined goals, such as achievement of return on equity and operating profit (Exh. NG-MPH-4, at 2).

Based on the analysis above, the Department finds that National Grid has adequately demonstrated that the costs associated with the Performance Plan are reasonable and that the Performance Plan is designed to encourage good employee performance and results in benefits to ratepayers. Therefore, the Department will permit the inclusion of National Grid's incentive compensation costs in its cost of service.

6. 401(k) Savings Plan Costs

a. Introduction

During the test year, National Grid booked $4,800,385 in 401(k) expenses, relating to costs charged to O&M for the employer's match for employee 401(k) plan contributions, of which $1,408,842 was directly incurred, $3,274,856 was allocated from NGSC, and $116,687 was allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 15, at 2 (Rev. 3)). The Company proposes to increase its 401(k) expenses by $339,868 to account for increases in test-year wages, attributable as follows: (1) $99,746 in direct costs; (2) $231,860 from NGSC; and (3) $8,262 allocated from all other companies (Exh. NG-RRP-2, Sch. 15, at 2 (Rev. 3)).

b. Positions of the Parties

National Grid asserts that its adjustment relates to the cost charged to O&M for the employer's match for employee 401(k) plan contributions and applies to Company, NGSC, and other affiliated company employees who charge time to the Company (Company Brief at 175, citing Exh. NG-RRP-1, at 41). The Company further claims that rate year base salaries and wages for the Company, NGSC, and other affiliated company employees are, in aggregate, 7.08 percent higher than the comparable test-year amounts (Company Brief at 175-176, citing Exh. NG-RRP-2, Sch. 15 (Rev. 2)). As a result, the Company maintains that it increased expenses charged to O&M by those same percentages (Company Brief at 176, citing Exh. NG-RRP-2, Sch. 15 (Rev. 2))

The Company claims that it also provided evidence to show that employees will contribute to the 401(k) plan at approximately the same level as was contributed during the test year (Company Brief at 104-105, citing Exh. NG-RRP-1, at 42-43). In addition, the Company maintains that employees are eligible to participate in the 401(k) plan on their first day of employment, and if they do not make a contribution election after 45 days with the Company they are automatically enrolled in a plan at a six percent contribution rate (Company Brief at 105, citing Exhs. NG-MPH-1, at 22; NG-RRP-1, at 42-43). National Grid argues that the analyses by the Company's plan administrator, Vanguard, demonstrate consistent pattern of employee contribution percentages to the 401(k) plan from year to year (Company Brief at 105). As a result of the above, the Company argues that the expenses are known and measurable and should be approved (Company Brief at 176). No intervenor addressed this issue on brief.

c. Analysis and Findings

National Grid proposes to increase the Company's 401(k) savings plan costs by $339,867, based on a proposed 7.08-percent[107] salary increase for union and non-union employees (Exh. NG-RRP-2, Sch. 15, at 2 (Rev. 3)). The Department has found that employee contributions to utility-sponsored savings plans are voluntary and, thus, subject to fluctuation. D.P.U. 13-90, at 102-104; Commonwealth Electric Company/Cambridge Electric Light Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67 (1991); Commonwealth Electric Company, D.P.U. 88-135/151, at 68 (1989). In the absence of a demonstration that the post-test-year participation levels are more representative of future participation than the total employee contributions made during the test year, the Department has declined to permit any adjustment above the expense booked during the test year. D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68.

Here, the Company's proposed increases are based on a percentage of employees' salaries – the known and measurable adjustment applied the overall percentage increase between adjusted test-year wages and rate year wages to the adjusted test-year 401(k) plan expense (Exhs. NG-RRP-1, at 42; NG-RRP-2, Sch. 15, at 2 (Rev. 3)). In other words, National Grid's proposed increases are based on the assumption that the increase in

---

107 The Company calculated a weighted average of the Boston Gas increase (6.48 percent) and the former Colonial Gas increase (9.67 percent) (see Exh. NG-RRP-2, Sch. 15, at 2 (Rev. 3)).

401(k) plan contributions will be consistent with the overall increases in salaries (Exhs. NG-RRP-1, at 42; NG-RRP-2, Sch. 15, at 2 (Rev. 3)). Thus, the Company's proposed increases are based on percentage increases to union and non-union salaries regardless of whether an employee participates in or makes contributions to the 401(k) savings plan.

In addition, the Company has not demonstrated that the post-test-year participation levels are more representative of future participation than those contributions made during the test year. In fact, the 401(k) plan participation rate for the service company declined from December 2018 to January 2019 due to an increase in the number of employees who chose not to contribute to the plan (Exhs. DPU 38-4; DPU 38-5).

Based on the foregoing, the Department disallows the Company's proposed increases associated with 401(k) plan costs. D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68. Accordingly, the Department reduces the Company's proposed cost of service by $339,867.

7. Health Care Costs

a. Introduction

During the test year, National Grid booked $19,099,422 in health care expenses, of which $10,229,992 were direct costs, $8,286,552 was allocated from NGSC, and $582,879 was allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 13, at 2 (Rev. 3)). National Grid proposes a reduction of $404,756, of which a reduction of $1,898,944 attributed to NGSC was partially offset by an increase of directly allocated costs of

$1,494,188 (Exh. NG-RRP-2, Sch. 13, at 2-3 (Rev. 3)). The Company's proposed adjustment to its health care expense reflects changes based on the Company's individual plan cost rates that will be in effect for calendar year 2021 (Exh. NG-MPH-1, at 30). The calculation of the rate year health care expense involved two steps: (1) the application of the most recently available health care program working rates to test-year employees enrolled in the health care programs to develop a total test-year health care expense, restated for 2020 working rates; and (2) the allocation of that total amount to O&M, and the further allocation of the NGSC portion to the Company (Exh. NG-RRP-1, at 39).

b. Positions of the Parties

National Grid states that a consultant, Mercer, helps determine the cost of health plans for the upcoming year for the Company's operating affiliates (Company Brief at 103, citing Exh. NG-MPH-1, at 31). The Company claims that the plans are self-insured, which means that actual plan utilization influences future costs (Company Brief at 103, citing Exh. NG-MPH-1, at 31). The consultant reviews national trend data as well as National Grid's own claims experience and plan design to calculate the working rates (Company Brief at 103, citing Exh. NG-MPH-1, at 31). National Grid claims that it is reasonable for the Department to utilize the working rates to determine the Company's benefit costs in the rate year, as this is similar to the method accepted by the Department in D.P.U. 15-155 (Company Brief at 103, citing Exh. NG-MPH-1, at 33).

National Grid points out that since the last rate case, the Company has made a number of changes to its union and non-union employee benefits plans in an effort to maintain market competitiveness and control costs (Company Brief at 173, citing Exh. NG-MPH-1, at 27-28). National Grid notes that the non-union benefit changes include offering a Select Provider Plan and Consumer Driven Health Plans, extending health care benefit coverage in all medical plans to include domestic partners and hearing aids, and introducing two new programs to assist employees and their family members in improving their health (Company Brief at 173-174, citing Exh. NG-MPH-1, at 28-29). For these reasons, the Company argues that the costs associated with their health care plans should be approved. No intervenor addressed this issue on brief.

c. Analysis and Findings

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

As an initial matter, the Department finds that National Grid's health care expenses are reasonable and that the Company has taken reasonable and effective measures to contain these costs (Exh. NG-MPH-1, at 24-27). For example, the majority of National Grid's health and welfare benefit plans are self-insured (Exh. NG-MPH-1, at 24; Tr. 1, at 74).

Further, the Company conducts periodic competitive bidding processes to minimize administrative fees and premiums when rolling out a new program or upon the expiration of an existing contract (Exh. NG-MPH-1, at 24). Third, the Company's prescription drug program is now run by CVS Caremark, which provides prescription drugs at a lower cost by leveraging a volume discount (Exhs. NG-MPH-1, at 25; AG 1-52, at 1). Fourth, medical benefit plan design changes included implementing 90 percent coinsurance, which eliminated first dollar coverage, increased deductibles, and out of pocket maximums, as well as reduced coinsurance for inpatient services (Exhs. NG-MPH-1, at 27; AG 1-52, at 3).

The Department has previously denied recovery of pro forma health care expenses based on working rates derived from actuarial estimates encompassing a broad-based pool of insured parties. D.P.U. 15-80/D.P.U. 15-81, at 137; D.P.U. 13-90, at 94. In this case, however, National Grid's working rate is derived using National Grid's own claims experience and plan design (Exh. NG-MPH-1, at 31). The Company's external benefits consultants developed the working rate using actuarial principles, and the rate is based on the Company's actual insurance claims and cost trends experienced during the two years prior to the test year (Exh. NG-MPH-1, at 32). Therefore, we conclude that National Grid's proposed working rates are sufficiently correlated to its own experience, rather than that of a broad-based pool of insured entities, to warrant its use in determining the Company's health care expense in this proceeding. See D.P.U. 15-155, at 176-177. Based on the foregoing, the Department accepts the Company's proposed health care expenses.

8. Miscellaneous Benefits

a. Introduction

During the test year, National Grid booked $107,250 in miscellaneous benefits expenses relating to costs charged to the Student Loan Repayment Program ("SLRP") and the Caregiver Program (Exhs. NG-RRP-2, Sch. 13, at 4 (Rev. 3); DPU 28-6 (Supp.); RR-DPU-8). Of the total, $75,639 was booked to the SLRP, and $31,611 was booked to the Caregiver Program (Exhs. DPU 28-3; DPU 28-6 (Supp.); RR-RPU-8).

National Grid introduced the SLRP in April 2018 to support employees with outstanding student loans or parent loans to help fund their child's education (Exhs. NG-MPH-1, at 28; DPU 28-4, Att.). Under this program, National Grid makes monthly payments toward the principal portion of student loans that the employees have taken to pay for their own education or their child's education to an accredited institution (Exhs. NG-MPH-1, at 28; DPU 28-4, Att.). In order to be eligible to participate, the employee must be a management employee and in active status (Exh. DPU 28-4, Att. at 2-3). Additionally, all student loans must be in the name of the employee who is participating in the program and cannot be past due, delinquent, or defaulted (Exh. DPU 28-4, Att. at 2). To receive the Company payment, employees must also continue making their own monthly payments toward their student loans while participating in the program (Exh. DPU 28-4, Att.). The repayment starts at $50 per month with an escalation factor of $25 per year, up to $150 per month and a maximum benefit of $6,000 per employee (Exhs. NG-MPH-1, at 28-29; DPU 28-4, Att.; DPU 28-5). The Company booked $75,639 in SLRP test year expenses and proposes a known and measurable adjustment of $39,276 to account for the forecast of SLRP expenses (Exh. NG-RRP-2, Sch. 13, at 4 (Rev. 3)).

The Company introduced the Caregiver Program in July 2018 to provide employees with access to high-quality child and elder care, along with programs and resources (e.g., educational advice for finances and college admissions, special needs parenting and support in finding caregivers for childcare, elder care, and household help) (Exhs. NG-MPH-1, at 29; DPU 28-7, Att.). National Grid subsidizes some Caregiver Program services (Exh. NG-MPH-1, at 29). The Company booked $31,611 in test-year costs associated with the Caregiver Program (Exhs. NG-RRP-2, Sch. 3, at 7 (Rev. 3); DPU 28-6 (Supp.); Tr. 1, at 138-139; RR-DPU-8).

b. Positions of the Parties

i. Attorney General

The Attorney General maintains that the Company must demonstrate that there is a link between the costs and ratepayer benefits to recover the costs associated with these programs (Attorney General Brief at 132, citing D.P.U. 93-60, at 201; D.P.U. 92-111, at 127). The Attorney General argues that the Company does not attempt to quantify with record evidence, such as studies or other data, the increased productivity that results from student loan or caregiver-related stress relief for management-level employees (Attorney General Brief at 132; Attorney General Reply Brief at 65). Accordingly, the Attorney General argues that the Company has failed to meet its burden of proof (Attorney General Reply Brief at 64, citing Town of Hingham v. Department of Telecommunications and

Energy, 433 Mass. 198, 213-14 (2001), citing Metropolitan District Commission, 352 Mass. 18, 24; Wannacomet Water Company v. Department of Public Utilities, 346 Mass. 453, 463 (1963); Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 7 n.5 (2001)).

Additionally, the Attorney General claims that, because these programs are new as of 2018 and this is the Company's first request to recover these costs from ratepayers, there is no precedent for allowing recovery for the associated expenses (Attorney General Brief at 133, citing Exh. DPU 28-7). The Attorney General points out that the Company admits there is no Department precedent for either program and offers no support for the claim that the SLRP or the Caregiver Program aids in the attraction or retention of highly skilled employees (Attorney General Reply Brief at 64).

Additionally, the Attorney General notes that these benefits do not appear to be typically offered to investor-owned utility management (Attorney General Reply Brief at 133). According to the Attorney General, the Company is not able to provide the number of other investor-owned utilities that offer student loan assistance to their non-union employees, and she claims that National Grid can point to only 14 other investor-owned utilities offering a similar Caregiver Program to non-union employees (Attorney General Brief at 133, citing Exhs. AG-JD-1, at 8-10; AG 19-11).

Finally, the Attorney General argues that the Company's attempt to recover these expenses from ratepayers appears particularly inappropriate given the current economic climate and the number of people who have lost their jobs and benefits (Attorney General Brief at 133, citing Exh. AG-JD-1, at 8-9). The Attorney General argues that ratepayers should not have to foot the bill for the education of non-union utility employees (or their children), nor should they pay for elder care or emergency childcare when many ratepayers cannot afford such luxuries for themselves (Attorney General Brief at 133).

ii. Company

The Company claims that in 2018, National Grid implemented the SLRP and the Caregiver Program to support a multi-generational workforce (Company Brief at 174, citing Exh. NG-MPH-1, at 28). According to the Company, these programs are designed to provide employees what they need to stay healthy, support their work/life needs, and maintain engagement and productivity to meet the needs of the business (Company Brief at 174, citing Exh. NG-MPH-1, at 28).

Regarding the SLRP, the Company asserts that it implemented the program to continue to attract and retain highly skilled employees, who often have significant student loan debt (Company Reply Brief at 43, citing Exh. DPU 28-4). National Grid notes that the SLRP will help ease the financial burden and stress of student loan repayments on employees and their families (Company Brief at 194, citing Exh. DPU 28-4; Company Reply Brief at 44). The Company concludes that, by easing these burdens, it allows employees to focus their attention on their jobs and increase productivity (Company Brief at 194, citing Exh. DPU 28-4; Company Reply Brief at 44). National Grid asserts that this is beneficial to customers because more focused employees improve efficiency, help with cost containment, and allow for continued safe and reliable service (Company Brief at 194; Company Reply Brief at 44, citing Exh. DPU 28-4).

National Grid adds that, although there is no Department precedent supporting the Company's decision to implement this program, many U.S. employers have either expanded or begun to offer student loan repayment assistance as a benefit (Company Brief at 194-195 & n.37; Company Reply Brief at 43). National Grid also points out that its New York affiliates have petitioned for recovery of student loan repayment programs (Company Brief at 195, citing Exh. DPU 28-4; Company Reply Brief at 43). According to National Grid, the SLRP is necessary to stay competitive in the market, especially as other companies begin to implement this type of benefit (Company Reply Brief at 43, citing Exh. DPU 28-4).

Regarding the Caregiver Program, National Grid argues that it was implemented to help employees manage their work/life commitments by providing backup care for family members when their primary caregiver is unavailable or in an emergency (Company Brief at 195; Company Reply Brief at 44). The Company claims that this service removes the stress on employees of having to find alternate care and allows them to focus their attention on their jobs and increase productivity, which in turn enables National Grid to provide safe, reliable, and efficient service to its customers (Company Brief at 195, citing Exh. AG 28-7; Company Reply Brief at 44). National Grid acknowledges that it is not aware of any Department precedent supporting the inclusion of these costs in the Company's cost of service but notes that its affiliates have petitioned for recovery of costs associated with similar programs (Company Brief at 195; Company Reply Brief at 44).

Finally, the Company argues that, although there is no direct Department precedent allowing the costs associated with the SLRP and Caregiver Program, the Department has found that employee fringe benefits may be allowed in the cost of service if there is some clear benefit to ratepayers (Company Reply Brief at 42, citing D.P.U. 92-78, at 38;[108] D.P.U. 92-210, at 48; Boston Gas Company v. Department of Public Utilities, 405 Mass. 115, 123-124 (1989)). Further, the Company contends that the Supreme Judicial Court has found that reasonable fringe benefits for employees help to attract and retain employees (Company Reply Brief at 42, citing Boston Gas, 405 Mass. 115, 123-124).

The Company asserts that it has demonstrated that these programs constitute employee benefits and these benefits will contribute to the attraction and retention of qualified employees to the benefit of customers (Company Reply Brief at 43, citing Exhs. DPU 28-4, Att.; DPU 28-7, Att.).

c. Analysis and Findings

The Company bears the burden of demonstrating that proposed costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred. D.P.U. 11-01/D.P.U. 11-02, at 323; D.T.E. 03-40, at 140-141; Oxford Water Company,

108 The Company argues that in D.P.U. 92-78, at 37, the Department allowed a fringe benefit consisting of matching employee charitable contributions where Massachusetts Electric Company ("MECo") argued the fringe benefit was intended to attract and retain good employees (Company Reply Brief at 42). The Company argues that MECo claimed that its ability to attract and retain good employees directly benefitted MECo's ratepayers because motivated employees are efficient (Company Reply Brief at 42, citing D.P.U. 92-78, at 37). As a result, National Grid concludes that the Department found that MECo's inclusion of the costs associated with the proposed fringe benefit was reasonable and allowed the costs to be recovered (Company Reply Brief at 42, citing D.P.U. 92-78, at 38).

D.P.U. 1699, at 13 (1984). This standard applies whether the expenses were incurred at the parent level or at the service company level. D.T.E. 03-40, at 140-141.

First, the Department must determine whether the costs associated with the SLRP and Caregiver Program benefit Massachusetts ratepayers. The Department commends the Company for offering programs such as the SLRP and Caregiver Program. Based on the evidence presented, however, the Department is not persuaded that, at this time, ratepayers should be responsible for these costs. National Grid has not provided any documentation that supports its claims that providing the SLRP benefits would ultimately lead to increased productivity or cost containment. Further, the Company has not supported its claims that the Caregiver Program leads to a direct increase in productivity and "further enables the Company to provide safe, reliable, and efficient service to its customers." Moreover, National Grid has not substantiated that it has been unable to attract and retain qualified employees. In fact, the Company and NGSC increased overall employee headcount by 135 in 2019 and by 275 in 2020 (Exhs. DPU 18-2, Att.; AG 7-7, Att.). Finally, the Company has not provided evidence demonstrating the industry standard as to student loan repayment assistance programs to justify including costs related to student loan repayment assistance and, according to the Company, only 14 other utilities offer a benefit like the Caregiver Program to non-union employees (Exhs. AG-JD-1, at 8-10; AG 19-11). Accordingly, the Department finds that the Company has not supported its claims that the SLRP and Caregiver Program provide benefits to ratepayers. While fringe benefits, such as these programs, may benefit ratepayers, a mere conclusory statement that fringe benefits promote employee good will, by itself will not be sufficient to demonstrate a direct benefit to ratepayers. See D.P.U. 92-78, at 39. Based on the foregoing, the Department disallows $114,915 in costs associated with the SLRP and $31,611 associated with the Caregiver Program. As a result of this decrease, inflation expense will be updated in Schedule 2A below. The Department may consider allowing such costs in a future proceeding, if the Company provides convincing evidence substantiating the relationship between these programs and ratepayer benefits and that these benefits are common industry practice and necessary for the Company to stay competitive in attracting skilled employees.

B. Depreciation Expense

1. Introduction

During the test year, National Grid booked $192,992,770 in depreciation expense, composed of $164,867,666 in depreciation expense for Boston Gas and $28,125,104 in depreciation expense for the former Colonial Gas (Exhs. NG-RRP-1, at 78-79; NG-RRP-2, Sch. 1, at 3 (Rev. 3); NG-RRP-2, Sch. 6, at 2 (Rev. 3)). In previous cases, National Grid presented separate depreciation studies for Boston Gas and the former Colonial Gas assets; however, in this case the depreciation study is for the combined assets of both companies pursuant to Department approval of the merger of the former Colonial Gas into Boston Gas in D.P.U. 19-69 (Exhs. NG-NWA-1, at 2, 7-8; NG-RRP-1, at 4, 6-7). National Grid initially proposed a consolidated rate year depreciation expense of $208,091,484, which reflected the application of depreciation accrual rates determined through a depreciation study to test-year-end utility plant in service (Exhs. NG-RRP-1, at 78-79; NG-RRP-2, Sch. 1, at 3;

NG-RRP-2, Sch. 6, at 2; NG-NWA-1, at 4). The Company's initial proposal represented an increase of approximately $15 million in depreciation expense over the test-year level (Exh. NG-RRP-1, at 78-79). During the proceeding, the Company updated its proposed rate year depreciation expense to $208,023,444 to reflect the removal of plant placed in service in error and mischarges from depreciation and plant assets (Exhs. NG-RRP-2, Sch. 1, at 3 (Rev. 3); NG-RRP-2, Sch. 6, at 2 (Rev. 3); DPU 36-15; DPU 36-16; DPU 36-27; AG 35-8).

National Grid proposes a phased-in implementation of depreciation rates, where the first two rate years utilize depreciation rates based on a "Shorter Service Lives Case 1" scenario and rate years three through five use higher depreciation rates based on a "Shorter Service Lives Case 2" scenario (Exhs. NG-RRP-1, at 79; NG-NWA-1, at 31-33). Both scenarios assume shorter service lives for three plant accounts[109] in anticipation of reductions in natural gas consumption and demand stemming from the Commonwealth's decarbonization goals, and both scenarios are based on the results of the Company's depreciation study (Exhs. NG-NWA-1, at 3, 23-26, 29-34; NG-NWA-3, at 11, 37-39; NG-NWA-4). Shorter Service Lives Case 1 results in a composite depreciation accrual rate of 3.47 percent and Shorter Service Lives Case 2 results in a composite depreciation accrual rate of 3.90 percent, compared to the Company's current depreciation composite accrual rate of 3.38 percent

---

109 National Grid assumes shorter service lives for Account 367.00 (Mains), Account 380.00 (Services), and Account 369.00 (Measuring and Regulating Station Equipment) (Exhs. NG-NWA-1, at 22, 31; NG-NWA-3, at 38).

(Exhs. NG-NWA-3, at 7, 54; NG-NWA-4, at 3; DPU 3-14, Att. at 2, 4). If applied to plant balances as of December 31, 2019, Shorter Service Lives Case 2 would produce a depreciation expense of $224.6 million (Exhs. NG-NWA-1, at 30; NG-NWA-3, at 7).[110]

In addition to the two shorter service life scenarios, the Company provided the results associated with a scenario where all current costs are recovered by the year 2050, two "Units of Production" scenarios based on different gas consumption forecasts, a "Sum-of-the-Years-Digits" scenario utilizing an accelerated method of depreciation, and a "Historical Experience" scenario based on the Company's actual historic retirement data (Exh. NG-NWA-1, at 29-30). During the proceeding National Grid suggested that if the Department does not approve the Shorter Service Lives scenarios, the "Historical Experience" would be most appropriate (Exh. NG-NWA-Rebuttal-1, at 51).

The Company's depreciation study is based on plant data as of December 31, 2019, that analyzes accounting entries of plant transactions from the period 1961 through 2019 (Exhs. NG-NWA-1, at 11; NG-NWA-3, at 36).[111] National Grid estimated the service life

---

110 The Company's proposal to implement Shorter Service Lives Case 2 in rate year three would result in a depreciation expense of approximately $260 million at that time (Exh. DPU 5-1, Att. 3). If applied to plant balances of December 31, 2019, Shorter Service Lives Case 1 would produce a depreciation expense of $200 million (Exh. NG-NWA-1, at 30). When applied to test-year-end plant balances, Shorter Service Lives Case 1 produces the proposed rate year depreciation expense of $208 million.

111 Aged retirement and other plant accounting data were compiled for the years 2004 through 2019, and unaged retirement data from 1961 to 2003 was statistically aged (Exhs. NG-NWA-1, at 7; NG-NWA-3, at 36).

and net salvage[112] characteristics for depreciable plant accounts, and next used the service life and net salvage estimates to calculate composite remaining lives and annual depreciation accrual rates for each account (Exhs. NG-NWA-1, at 10; NG-NWA-3, at 11-12). To determine service lives, the Company used the retirement rate method to create life tables, which, when plotted, show an original survivor curve that is then compared to Iowa Curves[113] to determine an average service life for each plant account (Exhs. NG-NWA-1, at 11-12; NG-NWA-3, at 14-15). To determine net salvage values, the Company reviewed its actual salvage and cost of removal data for the period 2006 through 2019 (Exhs. NG-NWA-1, at 14-15; NG-NWA-3, at 41).

With the exception of general plant assets, the Company relied on the straight-line remaining life method and average service life procedure to determine depreciation accrual rates (Exhs. NG-NWA-1, at 3, 15, 29; NG-NWA-3, at 6, 9-11). For general plant Accounts 391.00, 391.03, 393.00, 394.00, 395.00, 397.00, and 398.00, the Company proposes to use the straight-line amortization method (Exhs. NG-NWA-1 at 10, 17; NG-NWA-3, at 11, 47, 53). Additionally, National Grid proposes a five-year amortization

---

112 Net salvage is the resulting difference between the gross salvage of an asset when it is disposed less its associated cost of removal from service (Exh. NG-NWA-1, at 14).

113 Iowa Curves are frequency distribution curves initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; 18 curve types were initially published in 1935, and four additional survivor curves were identified in 1957 (Exh. NG-NWA-3, at 15-21). Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006). These curves are widely accepted in determining average life frequencies for utility plant.

for its general plant reserve variance associated with the implementation of amortization accounting (Exhs. NG-NWA-1, at 17; NG-NWA-3, at 54). As part of the depreciation study National Grid also proposes reserve transfers for subaccounts 362.04, 362.07, 363.07, 366.03, 381.00, 382.02, and 392.04 to correct for instances where book reserve exceeded the original cost of plant less net salvage, instances of negative book reserves, and instances where depreciation rates were higher than would be indicated by the recommended service lives and net salvage (Exh. NG-NWA-1, at 17-20). The Company's proposed reserve transfers are based on the theoretical reserves resulting from the study and do not result in a change in the overall level of book reserve, but the net result of these transfers is a net reduction in depreciation expense of approximately $500,000 (Exh. NG-NWA-1, at 19).

2. Positions of the Parties

a. Attorney General

The Attorney General recommends that the Department reject the Company's proposed depreciation rates and instead accept those proposed by her witness (Attorney General Brief at 95, 111; Attorney General Reply Brief at 59). The Attorney General argues her proposed depreciation rates are reasonable, based on accepted methodologies, and supported by empirical evidence (Attorney General Brief at 95, 107-108). The Attorney General proposes different average service lives and curves for five plant accounts and their associated subaccounts (Attorney General Brief at 99, citing Exh. AG-DJG-4).[114] The

[114] The five accounts, associated subaccounts, and proposed service lives and curves are: (1) Account 320.00 (Other Equipment), subaccounts 320.17 and 320.18, proposed 44-R2.5 curve; (2) Account 361.00 (Structures and Improvements),

Attorney General contends that the Company's "accelerated depreciation" proposal to shorten service lives for various accounts associated with the Commonwealth's decarbonization goals is premature and misplaced, particularly considering the Department's pending investigation in docket D.P.U. 20-80, which requires LDCs to work with consultants to comprehensively investigate the regulatory and policy actions required to meet such goals and provide a proposed plan by March 1, 2022 (Attorney General Brief at 96-97, citing Tr. 2, at 249; Attorney General Reply Brief at 56-58). The Attorney General maintains that approval of the Company's proposal would require the Department to make premature findings, and that the proposal makes inappropriate assumptions regarding the Company's inability to mitigate potential stranded costs or implement less costly solutions than full asset retirement (Attorney General Brief at 97).

The Attorney General also suggests National Grid's proposed depreciation rates are arbitrary and based on speculation concerning future obligations related to the Commonwealth's decarbonization goals rather than evidence (Attorney General Brief at 95, 98-99; Attorney General Reply Brief at 58-59). According to the Attorney General, the Company's proposed depreciation rates are excessively high due to underestimated service lives that are unreasonably short given the retirement data (Attorney General Brief at 98-99;

---

subaccounts 361.03, 361.07, 361.08, proposed 54-S1.5 curve; (3) Account 367.00 (Mains), subaccounts 367.12, 367.13, 367.14, 367.15, proposed 70-S1.5 curve; (4) Account 369.00 (Measuring and Regulating Station Equipment), subaccounts 369.00 and 369.07, proposed 55-R3 curve; and (5) Account 380.00 (Services), subaccounts 380.02 and 380.04, proposed 45-S1 curve (Attorney General Brief at 99, citing Exh. AG-DJG-4).

Attorney General Reply Brief at 58). Moreover, she notes that the Company's depreciation witness acknowledges there is uncertainty regarding the long-term impact of achieving statewide net zero emissions by 2050, and that greenhouse gas targets are based on economy-wide emissions that do not necessarily correspond to equivalent reductions in natural gas consumption (Attorney General Brief at 99, citing Exh. NG-NWA-1, at 24). In addition to being speculative, the Attorney General argues the Company's proposal is inconsistent with its own claims to be investigating ways to maintain its gas distribution system viability using renewable gas and green hydrogen (Attorney General Brief at 100, citing Exh. NG-FOH-1, at 43). Further, the Attorney General asserts that the Company's research indicates renewable natural gas is compatible with existing pipelines and gas equipment (Attorney General Brief at 100-101, citing Exh. NG-FOH-1, at 59-60).

Next, the Attorney General argues that the Company's proposal inappropriately shifts to ratepayers any potential risk associated with a gas transition (Attorney General Brief at 95, 101; Attorney General Reply Brief at 58-59). The Attorney General contends that shareholders are fully compensated for business risk through the setting of a reasonable rate of return on investment, and she suggests that the Company's cost of capital witness testified that the risks of decarbonization were considered when developing ROE recommendations (Attorney General Brief at 102, citing Exh. NG-AEB-1, at 62, 64; Boston Gas Company v. Department of Public Utilities, 368 Mass. 780, 789 (1975); Attorney General Reply Brief at 59). Accordingly, the Attorney General maintains that the Company's proposal would require ratepayers not only to carry the risk of depreciation, but also to pay the Company for carrying the same risk (Attorney General Brief at 103). The Attorney General notes the Company makes no explicit adjustment to its proposed rate of return to reflect the lowered risk associated with its depreciation proposal (Attorney General Brief at 103-104).

The Attorney General rejects any notion that future customers will be harmed unless the Department approves higher depreciation rates in this proceeding, and she argues that National Grid's proposed rates are not necessary to protect future customers from subsidizing current customers (Attorney General Brief at 105-107, citing Exh. NG-NWA-Rebuttal-1, at 8-25). Rather, the Attorney General contends that current customers subsidize future ratepayers in real terms due to the straight-line method of depreciation and the time-value of money (Attorney General Brief at 105-106). She also argues that current customers subsidize future ones as the return on rate base decreases as capital investment dollars reduce rate base and the associated return on rate base (Attorney General Brief at 106).

Finally, the Attorney General submits that the Company inaccurately calculated the stand-alone depreciation expense for Boston Gas and the former Colonial Gas by applying individual accrual rates to the stand-alone plant balances, rather than the proposed consolidated depreciation accrual rates (Attorney General Brief at 110, citing Exhs. NG-RRP-2, Sch. 6; AG-DJE-1, at 5-6). The Attorney General contends that to the extent that the stand-alone revenue requirements affect the ultimate design of rates, the stand-alone revenue requirements should reflect the consolidated Boston Gas depreciation rates that the Department approves (Attorney General Brief at 110-111, citing

Exh. AG-DJE-1, at 6). The Attorney General notes that the Company did not assert her recommendation was improper or incorrect (Attorney General Brief at 110).

b. TEC

TEC argues that the Company's proposed shorter service lives for certain accounts associated with the Commonwealth's decarbonization goals (i.e., Shorter Service Lives Case 2 scenario) are inappropriate and, as such, should be rejected (TEC Brief at 9-10, 13). TEC contends that the role of the natural gas utility sector within the context of the Commonwealth's decarbonization goals is complex, and that depreciation and capital spending should be examined closely as part of broader policy decisions in D.P.U. 20-80 rather than on a case-by-case basis (TEC Brief at 9-10). According to TEC, ratepayers should not have to support higher depreciation expense to account for a perceived risk of obsolescence while also funding aggressive capital spending that is forecasted to approach $1 billion per year by 2025 (TEC Brief at 9-10, citing Exh. DPU 5-14). While TEC opposes the Shorter Service Lives Case 2 scenario, it suggests the Department may consider adopting the Shorter Service Lives Case 1 as a more modest adjustment (TEC Brief at 10).

c. DOER

DOER states that while it would support the use of accelerated depreciation if accompanied by a granular analysis of anticipated impacts of decarbonization goals on the natural gas distribution system, the Company's proposal here is based on uncertainty and a lack of information (DOER Brief at 5; DOER Reply Brief at 1-2). DOER argues that the Department's investigation in D.P.U. 20-80 is the appropriate proceeding to evaluate the impacts of the Commonwealth's decarbonization goals on natural gas assets (DOER Brief at 5-6; DOER Reply Brief at 1-2). DOER notes that National Grid is the first LDC to request the Department's approval of depreciation rates that account for the potential impacts of the Commonwealth's decarbonization goals, and that the Company's depreciation witness acknowledged that it is not yet known what specific assets might be affected (DOER Brief at 5, citing Exhs. NG-NWA-1, at 24; DOER 1-1, at 1).

d. Company

i. Introduction

National Grid argues that the Department should reject the Attorney General's proposed depreciation accrual rates because they are flawed, do not reflect the Commonwealth's decarbonization goals, and ignore important information about the Company's assets (Company Brief at 275, 281-285; Company Reply Brief at 89-90). National Grid notes that the Attorney General does not challenge the Company's net salvage estimates, use of amortization accounting for general plant, or proposed reserve adjustments, but instead proposes different service lives for five plant accounts (Company Brief at 275, citing Exhs. NG-NWA-Rebuttal-1, at 11; AG-DJG-1, at 7).

With respect to the proposal to utilize amortization accounting for general plant accounts, National Grid contends that depreciation accounting is difficult for such accounts as they contain a large number of units but have small asset values, and that affected accounts represent less than one percent of depreciable plant (Company Brief at 270-271). Moreover, the Company maintains the Department previously has accepted similar proposals associated with amortization accounting (Company Brief at 270, citing D.P.U. 93-60, at 186). Regarding the proposed reserve transfers, National Grid maintains they are necessary to correct for the existence of negative book reserves that would have resulted in higher depreciation rates (Company Brief at 271). The Company asserts that the Department has previously approved similar proposals, and notes it results in no change to the total level of book reserve while reducing depreciation expense by approximately $500,000 (Company Brief at 271, citing D.P.U. 18-150, at 291).

ii. Shorter Service Lives

The Company responds to intervenor claims that its depreciation proposal is premature or speculative by insisting that the Department need not wait for the investigation in D.P.U. 20-80 to be completed to recognize that the Commonwealth's decarbonization goals will affect depreciation for gas utilities (Company Brief at 276; Company Reply Brief at 90-93). Rather, the Company asserts that a base distribution rate case and depreciation study are the proper forum to address the issue of depreciation and any recommendation to resolve these issues in docket D.P.U. 20-80 is an unnecessary delay tactic (Company Reply Brief at 89, 94-95). In this regard, National Grid notes that the Attorney General's depreciation witness in this proceeding acknowledges that the Commonwealth's decarbonization goals are legally mandated and may result in changes to gas utility operations and usage, and the Company points out that such changes are also referenced in the Attorney General's comments in D.P.U. 20-80 (Company Brief at 276-277, citing Tr. 11, at 1171, 1173, 1176, 1181; Company Reply Brief at 90, 92). The Company also maintains that the

Attorney General's proposal is at odds with her recognition that net zero emissions by 2050 could have profound impacts on the natural gas industry, and that unlike her proposal, the Company's depreciation expense considers such impacts (Company Brief at 271, 281-282, 284; Company Reply Brief at 90). National Grid contends that uncertainty will still exist after the investigation in D.P.U. 20-80 concludes, and that the path forward will be determined by customer and policy decisions over the next three decades rather than the stakeholders of D.P.U. 20-80 (Company Brief at 277-278; Company Reply Brief at 90). Further, the Company contends the Department is not required to predict what will occur by 2050, but rather whether the current depreciation proposal is reasonable at this time (Company Brief at 278; Company Reply Brief at 90). According to National Grid, preventing higher depreciation rates today that reflect the impact of the Commonwealth's decarbonization goals would deny the Company an opportunity to recover its capital investment, and it insists that an increase in depreciation resulting from decarbonization is a certainty (Company Brief at 279; Company Reply Brief at 90). National Grid avers it considered various scenarios that reflect the effects of decarbonization, and that its phased-in proposal to implement the Shorter Service Lives 1 scenario followed by the Shorter Service Lives 2 scenario appropriately and gradually recognizes future risks such as declines in consumption and customer migration (Company Brief at 271-273, 285; Company Reply Brief at 90, 91-93).

Regarding the intervenor claims that the Company's proposal shifts risk onto ratepayers, National Grid states that its proposal actually protects and reduces risks for future customers by reducing potential cost increases (Company Brief at 280; Company Reply Brief at 91, 95-96). In response to the contention that future customers do not need protection because they subsidize future customers already through the straight-line method of depreciation, National Grid states that the Attorney General's argument is based on a simplistic example of a single asset that is not relevant to real-world utility operations that utilize many assets of various vintages (Company Brief at 281). The Company argues that lower depreciation rates today could result in a higher depreciation expense and larger rate base in the future, and that any delay in recognizing the impacts of net zero emissions by 2050 will reduce the time left to pay remaining costs and potentially lead to confiscation (Company Brief at 274, 280; Company Reply Brief at 96-97). Additionally, the Company claims the regulatory environment has evolved such that utilities have an opportunity to recover their investments even when they are retired earlier than expected (Company Brief at 280).[115] National Grid suggests the Attorney General's specific claims with respect to ROE and risk are also misplaced and ironic as her recommendation appears to concede that her proposed ROE of 7.6 percent does not reflect the unique risks associated with decarbonization (Company Brief at 279). National Grid suggests, however, that if the Department does not approve the proposed phased-in depreciation and shorter service life scenarios to address concerns regarding decarbonization, the most appropriate service life

115 National Grid references coal-fired generation plants that were retired early, the costs of which were allowed to be recovered (Company Brief at 280).

estimates are those associated with the Company's "Historical Experience" scenario (Company Brief at 282, citing Exh. NG-NWA-Rebuttal-1, at 51).

As an additional point of clarification, National Grid notes that its proposal is not accelerated depreciation, as suggested by the Attorney General and other intervenors, and that the Company is simply seeking to recognize the impacts of decarbonization through shorter service lives for certain accounts (Company Reply Brief at 93-94). Nevertheless, the Company agrees that the investigation in D.P.U. 20-80 would be an appropriate venue to examine accelerated depreciation (Company Reply Brief at 93). National Grid also contends the Attorney General misstated and exaggerated the magnitude of the proposal, as she claims the rate year would see an increase over test-year depreciation of $29.4 million (Company Reply Brief at 93, citing Attorney General Reply Brief at 56). The Company argues that the increase is actually only $5 million[116] in rate year one, and $29 million in rate years three and beyond (Company Reply Brief at 93).

iii. Response to Attorney General – Specific Service Lives and Curves

As noted above, the Attorney General proposes different average service lives and curves for five plant accounts and their associated subaccounts (Attorney General Brief at 99, citing Exh. AG-DJG-4). Regarding Account 320.00 (Other Equipment), National Grid suggests its proposed 35-S2.5 curve is more reasonable than the 44-R2.5 curve proposed by

116 The actual increase is approximately $15 million in rate year one, and $29 million in rate year three (Exhs. NG-RRP-1, at 78-79; NG-RRP-2, Sch. 1, at 3 (Rev. 3); NG-RRP-2, Sch. 6, at 2 (Rev. 3); Company Reply Brief at 93).

the Attorney General (Company Brief at 282, citing Exh. NG-NWA-Rebuttal-1, at 56-57). Specifically, the Company argues that more than 65 percent of the assets in this account were added in the last two years, and that the most recent additions include vaporizers with lives closer to 30 years (Company Brief at 282, citing Exh. NG-NWA-Rebuttal-1, at 57). Further, National Grid indicates the assets in this account are located at LNG facilities constructed in the 1970s whose life spans are usually around 70 years (Company Brief at 282, citing Exh. NG-NWA-Rebuttal-1, at 56-57). According to the Company, when the entire LNG facilities are retired, the lives of the equipment at the facility will be limited (Company Brief at 282).

With respect to Account 361.00 (Structures and Improvements), the Company contends the Attorney General's proposed 54-S1.5 curve is too long in the context of typical LNG facility life spans since many of the investments in this account are related to work at the Company's Commercial Point LNG facility (Company Brief at 283). Similar to Account 320.00, the Company maintains that the assets in Account 361.00 were installed recently, with as much as 80 percent placed in service since 2018, and as such, its proposed 45-S1.5 curve is more appropriate (Company Brief at 283, citing Exh. NG-NWA-Rebuttal-1, at 59).

For Account 367.00 (Mains), the Company compares the 65-R3 curve from its Historical Experience scenario to the Attorney General's proposed 70-S1.5 curve (Company Brief at 283, citing Exh. NG-NWA-Rebuttal-1, at 61). National Grid argues that the Company's increased replacement of gas mains in recent years and the more recent band of dates suggest a shorter service life is more appropriate (Company Brief at 283-284). The Company also contends the assets to which this curve will apply are primarily plastic and steel mains installed since 1960, and therefore less than 60 years in age (Company Brief at 283).

In response to the Attorney General's proposed 55-R3 curve for Account 369.00 (Measuring and Regulating Station Equipment), the Company argues the proposed 50-R3 curve found in the Historical Experience scenario would be more reasonable (Company Brief at 284, citing Exh. NG-NWA-Rebuttal-1, at 64). The Company argues that its proposed curve is more consistent with the combined average service life of the two legacy companies (Company Brief at 284).[117] National Grid also suggests there could be a higher rate of replacement in the future, which could support a shorter service life for this account (Company Brief at 284).

Regarding Account 380.00 (Services), the Company suggests the 45-R2 curve found in the Historical Experience scenario would be more reasonable than the Attorney General's proposed 45-S1 curve for this account (Company Brief at 284, citing Exh. NG-NWA-Rebuttal-1, at 66). While both curves use the same service life of 45 years, National Grid contends that the R2 curve provides a better match to the overall experience band data, particularly the middle portion of the curve (Company Brief at 284).

117 For Account 369.00 (Measuring and Regulating Station Equipment), National Grid notes that Colonial Gas has a currently approved service life of 35 years (Company Brief at 284).

3. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 75 (1998); D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); D.P.U. 1350, at 97. Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a company reaches a conclusion about a depreciation study that is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132 (2002); D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[118] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances

118 Subjectivity is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; D.P.U. 1720, at 44; D.P.U. 1350, at 109-110.

associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A at 23 (1977).

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

b. Impact of Decarbonization and Phase-In

As part of the Company's depreciation study, National Grid presented six scenarios that demonstrate different approaches to calculate depreciation expense and incorporate assumptions regarding the impacts of decarbonization on the Company's assets, and one Historical Experience scenario (Exhs. NG-NWA-1, at 29-30; DPU 3-14, Att.). National Grid proposes to implement depreciation rates associated with the Shorter Service Lives Case 1 scenario during rate years one and two, and phase-in rates associated with the Shorter

Service Lives Case 2 scenario in rate years three through five (Exhs. NG-RRP-1, at 79; NG-NWA-1, at 31-33; DPU 3-12; DPU 11-3; DPU 11-8). With the exception of three accounts, both scenarios use the same estimated service lives and curves as those in the Historical Experience scenario, which is based on the Company's actual historical retirement data and depreciation study (Exhs. NG-NWA-1, at 31-34; DPU 3-14, Att. at 1-4). For Account 367.00 (Mains), Account 369.00 (Measuring and Regulating Station Equipment), and Account 380.00 (Services), National Grid assumes shorter service lives in both the Shorter Service Lives Case 1 scenario and the Shorter Service Lives Case 2 scenario to reflect what it contends are the potential impacts of the Commonwealth's decarbonization goals on the Company's assets (Exhs. NG-NWA-1, at 31-34; NG-NWA-3, at 11, 38; DPU 3-14, Att. at 1-4; Tr. 2, at 261-262). Compared to the Company's test-year depreciation expense, the Shorter Service Lives Case 1 scenario would represent an increase of approximately $15 million in years one and two, and the Shorter Service Lives Case 2 would increase depreciation by an additional estimated $29 million in years three through five of the Company's proposed PBR plan (Exhs. NG-RRP-1, at 78-79; NG-RRP-2, Sch. 1, at 3 (Rev. 3); NG-RRP-2, Sch. 6, at 2 (Rev. 3); DPU 5-1, Att. 1, at 4; DPU 5-1, Att. 3).

The Attorney General, TEC, and DOER argue the Company's proposed shorter service lives and phase-in associated with the Commonwealth's decarbonization goals is speculative and premature in light of the Department's open investigation in D.P.U. 20-80 (Attorney General Brief at 96-99; TEC Brief at 9-10; DOER Brief at 5-6). The investigation in D.P.U. 20-80 is ongoing, with independent consultant analyses of the impact of the

Commonwealth's climate goals on the natural gas industry and each LDC's proposal for helping the Commonwealth achieve its climate goals due by March 1, 2022 (Tr. 2, at 277-278; Tr. 11, at 1174-1176). D.P.U. 20-80, at 6. Therefore, any change to depreciation that is meant to reflect the impact of such goals would be anachronistic and premature at this time, particularly when this issue is of interest to, and will affect all LDCs (Exh. AG-DED-1, at 3; Tr. 2, at 246-250). D.P.U. 20-80, at 6; see also D.P.U. 93-60, at 330-331. The Company's depreciation witness has not had any discussions with the consultants retained by LDCs in D.P.U. 20-80 to inform his recommendations, nor has National Grid provided convincing or concrete support for the assumed shorter service lives associated with Accounts 367.00, 369.00, and 380.00 (Exhs. DPU 3-12; DPU 3-25; DPU 26-12; Tr. 2, at 253, 256, 278). While the Department recognizes the use of informed judgment in depreciation analysis, the current uncertainty surrounding the future of LDCs' operations and planning and associated cost implications, in addition to recognizing the Department's on-going investigation into issues related to these matters in D.P.U. 20-80,[119] lead us to conclude that it is not appropriate to approve the Company's proposed changes to depreciation at this time. Furthermore, the Department has not previously approved a proposal to phase-in an increase to depreciation expense during the term of a PBR mechanism

119 As noted in n.42 and Section V.D.1.c above, in docket D.P.U. 20-80, the Department initiated a process for exploring strategies to enable the Commonwealth to achieve its 2050 climate goals. D.P.U. 20-80, Vote and Order Opening Investigation at 1. The Department anticipates that future capital spending and related depreciation issues will be discussed in that proceeding as part of broader policy decisions affecting LDCs.

(Exh. DPU 3-1, at 1). The Department also notes that in other states and jurisdictions, such as New York and California, regulatory bodies also appear to be engaging in studies and investigations to examine the future of natural gas industry prior to implementing changes to depreciation methodology (Exh. DPU 3-1, at 1-2). Therefore, at this time, the Department rejects the Company's proposed phase-in of depreciation rates associated with the Shorter Service Lives Case 1 scenario and the Shorter Service Lives Case 2 scenario.

During the proceeding, National Grid requested that if the Department were to deny the Company's phase-in and assumptions regarding the Commonwealth's decarbonization goals, that it instead approve depreciation accrual rates associated with the Historical Experience scenario (Exhs. NG-NWA-Rebuttal-1, at 4, 51; Tr. 2, at 252-253). In Section VIII.B.3.f below, the Department evaluates the depreciation accrual rates for the five disputed accounts and compares the Attorney General's proposals with the Company's Historical Experience scenario.

c. Reserve Redistribution

The Company proposes to redistribute the recorded reserves for Account 362.04 – Gas Holders, Account 362.07 (Gas Holders - LNG), Account 363.07 (Other Equipment – LNG), Account 366.03 (Structures and Improvements – Other), Account 381.00 (Meters), Account 382.02 (Meter Installations), and Account 392.04 (Transportation Equipment) (Exhs. NG-NWA-1, at 17-19; DPU 3-6, Att.; DPU 11-5). National Grid argues that the proposed redistributions are necessary to address a number of issues, and that the redistributions are based on the theoretical reserves[120] resulting from the depreciation study (Exhs. NG-NWA-1, at 17-20; DPU 11-7). The Company explains that for some accounts, book reserves exceed the original cost less estimated net salvage due to an error with how the accounts were historically set up (Exhs. NG-NWA-1, at 17-18; DPU 3-3; DPU 11-5). Other accounts, such as meters and meter installations, have negative book reserves stemming from a large number of early retirements (Exhs. NG-NWA-1, at 18-19; DPU 3-5). The proposed redistributions are between related accounts and do not result in a change to the total level of recorded reserves (Exhs. NG-NWA-1, at 18-19; DPU 3-6, Att.).

The Department has reviewed the Company's proposed redistribution of recorded reserves and finds the circumstances underlying the redistribution are legitimate and the method by which they were redistributed is reasonable (Exhs. NG-NWA-1, at 17-20; DPU 3-3; DPU 3-5; DPU 3-6, Att.; DPU 11-5; DPU 11-7). The Department has also determined that any proposal to redistribute recorded reserves as part of a depreciation study requires a demonstration that the rebalancing is necessary and appropriate. D.P.U. 18-150, at 291. Based on the record evidence, the Department finds that the rebalancing of these recorded reserves is necessary and appropriate (Exhs. NG-NWA-1, at 17-20; DPU 3-3;

---

[120] Recorded reserves represent the net amount of depreciation expense actually charged to previous periods of operations, while theoretical reserves are estimated theoretically correct depreciation reserves based upon either past and/or future service life and net salvage considerations. National Association of Regulatory Utility Commissioners Manual: Public Utility Depreciation Practices, published August 1996, at 188, 325.

DPU 3-5; DPU 3-6, Att.; DPU 11-5; DPU 11-7). Therefore, the Department accepts the Company's proposed reserve redistribution.

d. Amortization of General Plant

National Grid proposes amortization accounting for certain general plant accounts, namely, Account 391.00 (Office Furniture and Equipment), Account 391.03 (Computers), Account 393.00 (Stores Equipment), Account 394.00 (Tools, Shop, and Garage Equipment), Account 395.00 (Laboratory Equipment), Account 397.00 (Communication Equipment), and Account 398.00 (Miscellaneous Equipment) (Exhs. NG-NWA-1 at 10, 17; NG-NWA-3, at 11, 47, 53). Amortization accounting is used for accounts with a large number of units, but relatively small asset values (Exhs. NG-NWA-1, at 16; NG-NWA-3, at 11). The Company's proposal is consistent with the requirements set forth by the FERC's Accounting Release 15 for General Plant Accounts utilizing Vintage Year Accounting (Exh. DPU 26-14). Moreover, the Department has previously approved similar proposals for other utilities (Exhs. DPU 3-4; DPU 26-14). D.P.U. 19-120, at 308-309; D.P.U. 14-150, at 197-198. Accordingly, the Department approves National Grid's proposed amortization of general plant accounts.

As part of its depreciation study, the Company identified $895,662 in unrecovered reserves associated with the amortization of general plant accounts (Exhs. NG-NWA-1, at 17; NG-NWA-3, at 54; DPU 3-4). The Company proposes to amortize the unrecovered reserves over a five-year period, resulting in an annual amount of $179,132 (Exhs. NG-NWA-1, at 17; NG-NWA-3, at 7, 54). As discussed in Section IV.D above, the Department approved the Company's PBR mechanism with a five-year term. As such, consistent with the amortization of other costs in the instant proceeding and the anticipated timing of the Company's next base distribution rate case, the Department finds that a five-year amortization period for the unrecovered reserves associated with the transition to amortization accounting is appropriate.

e. Stand-Alone Depreciation Calculation

As part of the Company's depreciation study, National Grid calculated the depreciation rates that would result from a separate study of Boston Gas and the former Colonial Gas assets and compared it to the combined proposed rate year depreciation expense (Exhs. NG-RRP-1, at 79-80; NG-NWA-1, at 8; NG-NWA-5-BOS; NG-NWA-6-COL; NG-NWA-7-BOS; NG-NWA-8-COL). The Attorney General contends that the Company should have calculated the depreciation expense for each stand-alone entity by applying the proposed consolidated depreciation accrual rates to Boston Gas and the former Colonial Gas plant balances, rather than separate depreciation accrual rates for each stand-alone entity (Attorney General Brief at 110-111; see also Exh. AG-DJE-1, at 6-8). Both parties agree that the dispute regarding the starting point of the calculation has no effect on the proposed consolidated depreciation expense (Exhs. AG-DJE-1, at 7; NG-RRP-Rebuttal-1, at 12). The Department accepts that the purpose of calculating the depreciation expense for the stand-alone entities is to demonstrate the effect of consolidation and illustrate that the consolidated depreciation expense would not be any greater than that of the separate entities combined (Exhs. NG-RRP-1, at 79-80; NG-RRP-Rebuttal-1, at 12). The Attorney General's recommendation does not change the conclusion of this demonstration, but nevertheless is inaccurate. If the Company were not proposing a depreciation expense on the combined assets of both Boston Gas and the former Colonial Gas, it would conduct separate depreciation studies for each entity and its plant assets, as it has in prior base distribution rate proceedings. D.P.U. 17-170, at 154-168; D.P.U. 10-55, at 358-377. National Grid's proposed consolidated depreciation accrual rates in the instant proceeding would not have been developed if the assets were studied separately, and, therefore, we find that the proper starting point for the Company's calculation is stand-alone depreciation accrual rates. Accordingly, the Department rejects the Attorney General's recommendation.

f. Accrual Rates

i. Account 320.00

For Account 320.00 (Other Equipment), which comprises two subaccounts, Boston Gas currently uses a 30-S4 curve, while the former Colonial Gas uses a 37-S4 curve (Exh. DPU 3-14, Att. at 1; RR-DPU-17 & Att. 1, at 1). National Grid's Historical Experience scenario proposes to replace the current curves with a 35-S2.5 curve, producing an accrual rate of 3.23 percent and 2.70 percent for subaccounts 320.17 (Other Equipment – LNG) and 320.18 (Other Equipment), respectively (Exhs. NG-NWA-3, at 52; AG-DJG-1, at 7; DPU 3-14, Att. at 1; AG 3-36, Att. 2; RR-DPU-17). The Attorney General, in contrast, proposes a 44-R2.5 curve and accrual rates of 2.48 percent and 2.13 percent for subaccounts 320.17 (Other Equipment – LNG) and 320.18 (Other Equipment), respectively (Exh. AG-DJG-1, at 7; RR-DPU-17 & Att. at 1).

Comparing the various curve proposals to the Company's retirement data, the curve that visually best approximates the longest band of data is the Attorney General's proposed 44-R2.5 curve (Exh. AG-DJG-1, at 19-20; RR-DPU-17, Att. at 1). The Attorney General's curve is also the best mathematically fitting curve, as it exhibits a sum-of-squared differences ("SSD")[121] of 0.0465, compared to the Company's curve, which exhibits an SSD of 1.8451 (Exh. AG-DJG-1, at 21). Further, the statistical analysis for the 1961 through 2019 experience band suggests curves with service lives extending in the 40- and 50-year range, which is consistent with the Attorney General's proposal (Exh. DPU 3-15, Att. 1, at 53).

Based on the foregoing analysis, the Department approves the Attorney General's proposed 44-R2.5 curve and the associated accrual rates of 2.48 percent and 2.13 percent, which when applied to the Account 320.17 and Account 320.18 test-year-end balances of $96,774,752 and $14,374,564, respectively, results in annual accruals of $2,400,014 and $306,178, respectively (Exhs. NG-RRP-2, Sch. 6, at 1 (Rev. 3); AG-DJG-1, at 7; AG-DJG-4). Compared to the Company's proposed accruals of $3,125,825, and $388,113, for Account 320.17 and Account 320.18, respectively, this result represents a combined decrease to depreciation expense of $807,746 (Exh. NG-RRP-2, Sch. 6, at 1 (Rev. 3)).[122]

121 SSD is a measure of the distance between the proposed Iowa Curve and the observed life table, such that a lower SSD signifies a better mathematical fit (Exh. AG-DJG-1, at 21).

122 $807,746 = ($3,125,825 + $388,113) – ($2,400,014 + $306,178)

ii. Account 361.00

For Account 361.00 (Structures and Improvements), which comprises three subaccounts, Boston Gas currently uses a 50-R3 curve for subaccounts 361.03 (Structures and Improvements) and 361.08 (Structures and Improvements – LNG Tanks) and a 30-S3 curve for subaccount 361.07 (Structures and Improvements), while the former Colonial Gas uses a 25-R2 curve for subaccount 361.03 and a 30-S3 curve for subaccount 361.07 (Exh. DPU 3-14, Att. at 1; RR-DPU-17 & Att. at 2).[123] National Grid's Historical Experience scenario proposes to replace the current curves with a 45-S1.5 curve for all three subaccounts, producing accrual rates of 4.04 percent, 2.16 percent, and 2.53 percent for subaccounts 361.03 (Structures and Improvements), 361.07 (Structures and Improvements – LNG), and 361.08 (Structures and Improvements – LNG Tanks), respectively (Exhs. NG-NWA-3, at 52; AG-DJG-1, at 7; DPU 3-14, Att. at 1; AG 3-36, Att. 2; RR-DPU-17 & Att. at 2). The Attorney General, in contrast, proposes a 54-S1.5 curve and accrual rates of 2.73 percent, 1.82 percent, and 2.03 percent for subaccounts 361.03 (Structures and Improvements), 361.07 (Structures and Improvements – LNG), and 361.08 (Structures and Improvements – LNG Tanks), respectively (Exh. AG-DJG-1, at 7; RR-DPU-17 & Att. at 2).

Comparing the proposed curves visually against the Company's retirement data, the curve that best approximates the data points in the longest experience band is the Attorney

[123] There is no subaccount 361.08 currently associated with the former Colonial Gas (Exh. NG-NWA-6-COL at 1; RR-DPU-17).

General's proposed 54-S1.5 curve (Exh. AG-DJG-1, at 23; RR-DPU-17, Att. at 2). The Attorney General's curve is also the best mathematically fitting curve, as it exhibits an SSD of 1.5025, compared to the Company's curve which exhibits an SSD of 5.2770 (Exh. AG-DJG-1, at 23-24). In a review of comparable utilities with Account 361.00, a majority utilize curves with average service lives of 50 years or more, while fewer than a quarter of companies have curves with average service lives of 45 years (Exh. DPU 3-2, Att.). Further, the statistical analysis for both the 1961 through 2019 experience band and the 2004 to 2019 experience band suggest curves with longer service lives as those with the best fit (Exh. DPU 3-15, Att. 1, at 62, 66).

Based on the foregoing analysis, the Department approves the Attorney General's proposed 54-S1.5 curve and the associated accrual rates of 2.73 percent, 1.82 percent, and 2.03 percent, which when applied to the Account 361.03, 361.07, and 361.08 test-year-end balances of $940,896, $108,944,367, and $1,471,805, respectively, results in annual accruals of $25,686, $1,982,787, and $29,878, respectively (Exhs. NG-RRP-2, Sch. 6, at 1 (Rev. 3); AG-DJG-1, at 7; AG-DJG-4). Compared to the Company's proposed accruals of $38,012, $2,353,198, and $37,237, for subaccounts 361.03, 361.07, and 361.08, respectively, this result represents a combined decrease to depreciation expense of $390,096 (Exh. NG-RRP-2, Sch. 6, at 1 (Rev. 3)).[124]

[124] $390,096 = ($38,012+ $2,353,198 + $37,237) – ($25,686 + $1,982,787 + $29,878)

iii. Account 367.00

For Account 367.00 (Mains), which comprises four subaccounts based on material type, Boston Gas currently uses a 70-R3 curve for the total account, while the former Colonial Gas uses a 60-S4 curve for the total account (Exh. DPU 3-14, Att. 1, at 1; RR-DPU-17 & Att. at 3). National Grid's Historical Experience scenario proposes to replace the current curves with a 65-R2.5 curve for the total account, producing an accrual rate of 2.88 percent for Account 367.00 (Mains) (Exh. AG-3-36, Att. 2; RR-DPU-17 & Att. at 3). The Attorney General, in contrast, proposes a 70-S1.5 curve and accrual rate of 2.64 percent for the total Account 367.00 (Mains) (Exh. AG-DJG-5, at 1; RR-DPU-17 & Att. at 3).

A comparison reveals that the curves associated with the Historical Experience scenario and the Attorney General's proposal both follow a similar trajectory and approximate the Company's retirement data until 55 years, at which point they begin to diverge (RR-DPU-17, Att. at 3). After 55 years, the Historical Experience scenario curve strikes the most appropriate balance between the two experience bands, particularly considering the Company's recent and ongoing main replacement activity (Exh. NG-NWA-Rebuttal-1, at 61; RR-DPU-17, Att. at 3). As such, the more recent 2004 to 2019 experience band should be given more consideration, and the statistical analysis associated with this experience band suggests the best fitting curves have average service lives ranging in the high 50- to 60-years (Exh. DPU 3-15, Att. at 95). Moreover, the 70-S1.5 curve proposed by the Attorney General suggests that some assets in the account will survive beyond 120 or 130 years, which is not supported by the Company's retirement data or currently approved curves (Exh. AG 3-36, Att. 3, at 27-35; RR-DPU-17, Att. at 3).

Based on the foregoing analysis, the Department approves the Historical Experience scenario 65-R2.5 curve and the associated accrual rate of 2.88 percent, which when applied to the Account 367.00 adjusted test-year-end total balance of $3,155,644,776,[125] results in an annual accrual of $90,882,570 (Exhs. NG-RRP-2, Sch. 6, at 1 (Rev. 3); AG 3-36, Att. 2). Compared to the Company's proposed Shorter Service Lives scenarios accrual of $103,313,982 for the rate year, this result represents a decrease to depreciation expense of $12,431,412 (Exh. NG-RRP-2, Sch. 6, at 1 (Rev. 3)).

iv. Account 369.00

For Account 369.00 (Measuring and Regulating Station Equipment), which comprises two subaccounts, Boston Gas currently uses a 55-R3 curve for the total account, while the former Colonial Gas uses a 35-S5 curve for the total account (Exh. DPU 3-14, Att. 1, at 1; RR-DPU-17 & Att. at 3). National Grid's Historical Experience scenario proposes to replace the current curves with a 50-R3 curve for the total account, producing accrual rates of 3.41 percent and 3.40 percent for Account 369.00 (Measuring and Regulating Station Equipment) and Account 369.07 (Measuring and Regulating Station Equipment – Commercial Point), respectively (Exh. AG 3-36, Att. 2; RR-DPU-17 & Att. at 3). The Attorney General, in contrast, proposes a 55-R3 curve and accrual rates of 2.88 percent and

---

125 As discussed in n.81 above, the Department disallowed $33,058,363 of plant from Account 367 associated with Q1 2020 GSEP investments.

2.96 percent for the same two accounts (Exhs. AG-DJG-4; AG-DJG-5, at 2; RR-DPU-17 & Att. at 3).

A comparison reveals that the curves associated with the Historical Experience scenario and the Attorney General's proposal both deviate from the observed data after 30 years; however, the curve that best aligns with the data prior to that point is the 50-R3 curve associated with the Historical Experience scenario (RR-DPU-17, Att. at 3). Additionally, an average service life of 50 years is more consistent with the service lives and curves utilized by other utilities with the same account (Exhs. DPU 3-2, Att.; DPU 3-25). The Department also finds that the Historical Experience curve strikes a reasonable balance between the current average service lives used by Boston Gas and the former Colonial Gas (RR-DPU-17).

Based on the foregoing analysis, the Department approves the Historical Experience scenario 50-R3 curve and the associated accrual rates of 3.41 percent and 3.40 percent, which when applied to the Account 369.00 and subaccount 369.07 test-year-end total balances of $217,724,209 and $5,519,032, respectively, results in annual accruals of $7,424,396 and $187,647, respectively (Exhs. NG-RRP-2, Sch. 6, at 1 (Rev. 3); AG 3-36, Att. 2). This result leads to no change to the Company's proposed rate year accrual for Account 369.00 (Measuring and Regulating Station Equipment) (Exh. NG-RRP-2, Sch. 6, at 1 (Rev. 3)).[126]

[126] While the Department rejects the Company's proposed shorter service lives for Account 369.00, the Historical Experience and Shorter Service Lives Case 1 scenarios

v. Account 380.00

For Account 380.00 (Services), which comprises two subaccounts, Boston Gas currently uses a 47-S1.5 curve, while the former Colonial Gas uses a 47-S2 curve (Exh. DPU 3-14, Att. at 1; RR-DPU-17 & Att. 1, at 5). National Grid's Historical Experience scenario proposes to replace the current curves with a 45-R2 curve, producing an accrual rate of 3.08 percent for the total Account 380.00 (Services) (Exh. AG 3-36, Att. 2; RR-DPU-17 & Att. at 5). The Attorney General, in contrast, proposes a 45-S1 curve and an accrual rate of 3.24 percent for the total Account 380.00 (Services) (Exh. AG-DJG-5, at 2; RR-DPU-17 & Att. at 5).

While both proposed curves use an average service life of 45 years, a comparison against the Company's retirement data reveals that the 45-R2 curve associated with the Historical Experience scenario provides a better approximation to both experience bands, particularly the middle portion of the larger 1961 to 2019 band (RR-DPU-17, Att. at 5). Regarding comparable utilities, the most common curves used for Account 380.00 (Services) are right moded, or "R" curves, with R2 curves being most represented, which is consistent with the Company's Historical Experience scenario (Exhs. NG-NWA-3, at 15; DPU 3-2, Att.).

Based on the foregoing analysis, the Department approves the Historical Experience scenario 45-R2 curve and the associated accrual rate of 3.08 percent, which when applied to

---

result in the same proposed curves and, therefore, no change to the rate year proposal (RR-DPU-17).

the Account 380.00 adjusted test-year-end total balance of $1,580,763,443,[127] results in an annual accrual of $48,687,514 (Exhs. NG-RRP-2, Sch. 6, at 1 (Rev. 3); AG 3-36, Att. 2). Compared to the Company's proposed Shorter Service Lives scenarios accrual of $58,302,509 for the rate year, this result represents a decrease to depreciation expense of $9,614,995 (Exh. NG-RRP-2, Sch. 6, at 1 (Rev. 3)).

g. Conclusion

Based on the analysis above, the Department finds that the appropriate depreciation expense reflects a combination of the Company's Historical Experience scenario and two curves proposed by the Attorney General. The adjustments to depreciation expense herein, as well as reductions to plant in service detailed in Section VI.B.6.b and n.81 above, result in a total reduction of $23,413,783[128] to the Company's proposed depreciation expense of $208,023,444 (Exh. NG-RRP-2, Sch. 6, at 2 (Rev. 3)). Therefore, the Department approves a depreciation expense of $184,609,661.

---

[127] As discussed in n.81 above, the Department disallowed $16,565,559 of plant from Account 380 associated with Q1 2020 GSEP investments.

[128] The total disallowance includes the adjustments to Accounts 320, 361, 367 and 380 discussed above, as well as a reduction of $169,534 to depreciation expense associated with the reductions in plant for Accounts 381, 382, and 383, discussed in Section VI.B.6.b and n.81 above.

C. Gas Business Enablement Program

1. Introduction

National Grid's Gas Business Enablement ("GBE") program is a multi-year, enterprise-wide initiative the Company designed to implement work management,[129] asset management,[130] and customer enablement[131] operating capabilities to support National Grid USA's three-state, U.S. gas distribution businesses. D.P.U. 17-170, at 206-207.[132] Upon completion, the GBE program will result in a streamlined operating platform that reduces the number of existing sub-systems, applications, and databases in Massachusetts utilized for the Company, and will include three core systems: (1) asset management data and business

---

129 Work management means the systems used to coordinate, document, and manage all work projects completed by the Company. The work management system will have an integrated field mobile application allowing a single view of all work and the ability to prioritize work. D.P.U. 17-170, at 206 n.112.

130 Asset management means the platform to coordinate, document, and manage the installation, maintenance, and repair of distribution assets. The asset management system will be integrated with the work management system, and it will provide a single view of all assets on the record. D.P.U. 17-170, at 206 n.113.

131 Customer enablement means the platform used for customer relationship management. The customer enablement platform will be integrated with the work management system to enable easier customer interactions through greater visibility to planned activities and scheduling of upcoming work. D.P.U. 17-170, at 206 n.114.

132 At the time of the filing in this proceeding, National Grid operated gas distribution businesses in Massachusetts, New York, and Rhode Island (Exh. NG-ITP-1, at 20). As noted in n.7 above, the Department approved a waiver related to the sale of the Rhode Island operations. D.P.U. 21-60, at 39. In that Order, the Department documented National Grid USA's commitment not to reallocate the Rhode Island portion of the GBE-related costs to the Company's other operating companies, including the Massachusetts distribution companies. D.P.U. 21-60, at 35.

process using IBM Maximo, with integration to Environmental Systems Research Institute for spatial functions; (2a) work management/work planning data and business processes using IBM Maximo; (2b) work management/schedule, dispatch, and mobility data and business process using SalesForce.com; and (3) customer engagement data and business process using SalesForce.com. D.P.U. 17-170-B at 37; D.P.U. 17-170, at 207, 239.

In National Grid's last base distribution rate case, the Company sought approval of a discrete cost-recovery program to support its GBE program and recover the actual program costs that the Company would incur in the future. D.P.U. 17-170, at 210. At the time of the Department's decision in D.P.U. 17-170, National Grid anticipated starting information systems investment upgrades in Massachusetts in December 2018, although they had already incurred non-recurring O&M costs related to the GBE program. D.P.U. 17-170, at 243. The Company specified that the program's implementation would require significant annual investment (both O&M and NGSC capital additions) across National Grid USA's three-state, U.S. gas distribution operations through 2023. D.P.U. 17-170, at 206-207, 208, 237, 243.

After review of National Grid's proposal, the Department found that the GBE program was necessary to improve the efficiency and effectiveness of the Company's operations, which would improve customer experiences and promote a safer and more reliable natural gas infrastructure. D.P.U. 17-170, at 238-240. Having found the information system upgrades were necessary to the Company's operations, the Department determined that alternative special ratemaking treatment for the GBE program was appropriate. D.P.U. 17-170, at 240.

Ultimately, the Department allowed National Grid to: (1) recover through base distribution rates approximately $1.47 million[133] of non-recurring GBE program O&M costs incurred during the test year (i.e., January 1, 2016, through December 31, 2016); and (2) establish a separate recovery mechanism ("GBE Tracker") within the Company's Local Distribution Adjustment Clause ("LDAC") to recover the actual O&M and capital costs incurred by NGSC and allocated to the Company as rent expense, less the amounts collected through base distribution rates. D.P.U. 17-170, at 1, 241-245. In approving special ratemaking treatment for National Grid, the Department found that the GBE Tracker was designed to provide the Company cost recovery of GBE-related investments between base distribution rate cases, as well as provide ratepayers with necessary protections and cost savings, all while ensuring the Department's regulatory oversight. D.P.U. 17-170, at 248.

In conjunction with the approval of the GBE Tracker, the Department directed the Company to file annual GBE rate adjustment and reconciliation filings to demonstrate that costs sought for recovery were incremental (i.e., the costs were not associated with projects currently recovered through base distribution rates), prudently incurred, and used and useful. D.P.U. 17-170, at 245-246.[134] The Department noted that to the extent that it approved costs

---

133 Specifically, the Department allowed $1,204,449 for Boston Gas and $269,437 for the former Colonial Gas to be collected through base distribution rates. D.P.U. 17-170, at 243-244.

134 The Department found that National Grid could not accrue interest on investments during the time period between when the Company incurred the costs and when the Company recovered the costs through rates. D.P.U. 17-170, at 245-246.

for collection through the GBE Tracker that later were found to provide minimal or no benefits to ratepayers, the Department reserved the right to remedy this deficit through appropriate regulatory actions. D.P.U. 17-170, at 247. Additionally, the Department required the Company to provide with the annual filings testimony that showed the benefits and any cost savings of GBE-related investments made on behalf of ratepayers. D.P.U. 17-170, at 247-248.

Since the establishment of the GBE Tracker in D.P.U. 17-170, the Company has made three annual GBE filings. In the first filing, the Department allowed the Company to recover $5,677,445 in calendar year 2018 GBE program costs through proposed gas business enablement factors ("GBEFs") effective November 1, 2019. Boston Gas Company/Colonial Gas Company, D.P.U. 19-87-A at 1, 24 (2019). In the second filing, the Department allowed the Company to recover $8,611,589 in calendar year 2019 GBE program costs through GBEFs effective November 1, 2020, subject to further investigation and reconciliation pursuant to the Department's ongoing investigation. Boston Gas Company/Colonial Gas Company, D.P.U. 20-78, at 3, 8 (2020). Final approval of the calendar year 2019 GBE costs still is pending. The Company recently made its third filing and seeks to recover $7,268,325 in calendar year 2020 GBE program costs. Boston Gas Company, D.P.U. 21-54, Prefiled Joint Testimony of James Patterson and Amy F. Solomon at 30-31 (August 2, 2021).

2. Company Proposal

National Grid states that due to several factors, including roll-out issues in Rhode Island, delays in deployment to New York affiliates, and the impact of the COVID-19 pandemic, the "Go Live" date of the GBE program in Massachusetts has been delayed from November 2021[135] to an anticipated date of May 2022 (Exhs. NG-ITP-1, at 22-23, 25; DPU 31-5, at 2; DPU 35-1; DPU 35-3). Thus, the Company proposes to continue the special ratemaking treatment approved in D.P.U. 17-170, with several modifications, until the program is fully implemented in Massachusetts (Exh. NG-ITP-1, at 24-25).

In particular, the Company proposes to increase the costs recovered through base distribution rates from \$1.47 million to \$7.89 million (Exhs. NG-ITP-1, at 19; DPU 21-2, Att.; DPU 21-3; DPU 39-1).[136] The Company states that these costs are comprised of one-time labor costs for employees working on the system, consultants, contractors, employee expenses, materials, other employee benefits, other expenses, overtime, and transportation costs (Exh. NG-ITP-1, at 19). Further, National Grid states that the \$7.89 million in costs represents the actual GBE program implementation costs through the

---

135 In National Grid's first annual GBE filing, the Company anticipated full implementation of the GBE program in Massachusetts by October 2020. D.P.U. 19-87, Exh. NG-1, at 16. In National Grid's second annual GBE filing, the Company anticipated full implementation of the GBE program in Massachusetts by November 2021 (Exh. NG-ITP-1, at 7). See also D.P.U. 20-78, Exh. NG-1, at 15-16.

136 Specifically, the Company states that \$6,109,323 was allocated to Boston Gas and \$1,778,064 was allocated to the former Colonial Gas (Exhs. DPU 21-2, Att.; DPU 21-3).

test year that were allocated to Boston Gas and the former Colonial Gas (Exh. NG-ITP-1, at 19). The Company proposes that this amount would be the new allowance recovered through base distribution rates and the amount that would be deducted from the recovery level allowed through the GBE Tracker going forward (Exh. NG-ITP-1, at 19).

Next, National Grid proposes to continue to recover through the GBE Tracker the annualized rent expense allocated to the Company and certain costs it incurs to support the GBE system architecture and operations and that are not currently recovered in base distribution rates (Exh. NG-ITP-1, at 18-19). The Company states that these costs include: (i) hardware, software, and mobile solutions license maintenance fees and subscriptions; and (ii) support costs to maintain certain legacy applications following implementation until legacy applications are replaced or maintained in an upgrade future state as appropriate (Exh. NG-ITP-1, at 19-20). According to the Company, these are costs necessary to support the delivery of the GBE Program through the implementation phase and that following the Go Live date some of these costs will continue as normally recurring expenses of running the system to support the delivery of the GBE Program to the business (Exh. NG-ITP-1, at 19-20). The Company forecasts annual incremental GBE program costs of $14,658,007, which it proposes to recover through the GBE Tracker until the GBE program implementation is complete, the system goes live in May 2022, and the GBE Tracker is terminated, as discussed below (Exh. NG-IPT-1, at 24-25).[137]

---

[137] The projected annual recovery of $14,658,007 is comprised of the following: (1) $12,103,115 of depreciation; (2) $5,211,091 return on asset; and (3) $5,231,188 ongoing support, less the proposed $7,887,387 recovered through base distribution

Third, the Company proposes to transition all Massachusetts-related GBE program costs into base distribution rates as part of the Company's annual PBR adjustment filing to take effect on October 1, 2023 (Exhs. NG-ITP-1, at 25; DPU 21-3; DPU 50-6). National Grid proposes that upon transition of all GBE-related costs to base distribution rates, the GBE Tracker would be terminated (Exhs. NG-ITP-1, at 25; DPU 21-3). At the time of National Grid's PBR adjustment for effect October 1, 2023, the Company would include in base distribution rates the annual incremental GBE-related costs estimated at $14,658,007 discussed above (Exhs. DPU 5-1, Att. 1, at 4, 7 (Supp. 3); DPU 5-1, Att. 4 (Supp. 2); DPU 21-3; DPU 21-4; DPU 35-6 & Att.; DPU 39-2; DPU 42-6 & Att.).[138]

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's proposed modifications to the GBE Tracker are unnecessary and unreasonable (Attorney General Reply Brief at 19). In particular, the Attorney General contends that the Department should reject the Company's

---

rates (Exhs. DPU 5-1, Att. 1, at 4, 7 (Supp. 3); DPU 5-1, Att. 4 (Supp. 2); DPU 21-3; DPU 21-4; DPU 35-6 & Att.; DPU 39-2; DPU 42-6 & Att.).

138 As noted above, the Company seeks to increase the amount recovered through base distribution rates from $1.47 million to $7.89 million (Exhs. NG-ITP-1, at 19; DPU 21-2, Att.; DPU 21-3; DPU 39-1). Although the Company removes the $7.89 million from its calculation of the amount to be recovered through the GBE Tracker and then transitioned to base distribution rates (i.e., the $14.7 million amount), at the time of the proposed transition to base distribution rates in the 2023 PBR filing, the Company's cost of service, if approved as proposed, would continue to include $7.89 million in GBE-related costs.

proposal to increase the amount of non-recurring O&M costs recovered through base distribution rates from $1.47 million to $7.89 million (Attorney General Reply Brief at 19). The Attorney General claims that the Department had previously determined that non-recurring test-year costs should be routinely removed from test-year cost of service (Attorney General Reply Brief at 19-20, citing D.P.U. 17-170, at 243). Further, the Attorney General argues that the current allowance of $1.47 million in base distribution rates for the GBE program already burdens existing ratepayers in advance of any benefits from the GBE program and weakens regulatory lag by frontloading cost recovery (Attorney General Reply Brief at 20). In addition, the Attorney General notes that GBE-related annual costs fluctuate, so the amount requested by the Company is unrepresentative of the incurred costs (Attorney General Reply Brief at 20). Moreover, the Attorney General also argues that the Company already has the means to recover actual GBE program costs incurred through the GBE Tracker and has recovered costs sought in dockets D.P.U. 20-78 and D.P.U. 19-87 (Attorney General Reply Brief at 20-21).

According to the Attorney General, increasing the Company's amount of recovery through base distribution rates would dramatically increase ratepayer risk that the Company will fail to control costs or fail to successfully implement the GBE program on schedule (Attorney General Reply Brief at 21). On this last point, the Attorney General contends that there have been repeated delays in implementing the GBE program in Massachusetts so that the Go Live date has been pushed out from an initial date of December 2020 to May 2022 (Attorney General Reply Brief at 21). Further, the Attorney General notes that total project costs have increased significantly from the Company's last base distribution rate case and that the recent management audits have raised questions about the future of the GBE program in Massachusetts (Attorney General Reply Brief at 21, citing Exh. DPU 53-4, at 165). Thus, the Attorney General asserts that the Department should make no changes to the current amount of GBE-related cost that the Company recovers though base distribution rates to balance risks between ratepayer protection and the Company's financial needs (Attorney General Reply Brief at 21).

The Attorney General also argues that the Department should decline to specify, at this time, how the interim recovery of GBE costs should be transitioned to base distribution rates once the GBE program is fully implemented (Attorney General Reply Brief at 21). In particular, the Attorney General contends that in addition to the delayed Go Live date and increased costs, ratepayer benefits from the GBE program are speculative and, in fact, the Company claims no benefits will accrue unless and until the entire project is complete (Attorney General Reply Brief at 22, citing Exh. DPU 35-2). Thus, she argues that there can be no determination until after the Go Live date whether and to what extent any GBE costs incurred were reasonable and prudent and whether the investments are used and useful (Attorney General Reply Brief at 21-22).

Further, the Attorney General argues that because National Grid already recovers cost through the GBE Tracker and will continue to do so after the Go Live date and until the Company's next base distribution rate case, there is no need to establish a transition of cost recovery from the GBE Tracker to base rates (Attorney General Reply Brief at 23).

According to the Attorney General, the Company's motivation to transition cost recovery to base rates is to "'grow' these revenues" by applying the annual PBR adjustment factor to the amounts recovered (Attorney General Reply Brief at 23, citing Company Brief at 333-334). In this regard, the Attorney General argues that the Company's proposal to include in base distribution rates what she claims are largely one-time, non-recurring GBE project costs, and for those costs to be subject to the annual PBR adjustment formula is unjust and inequitable to ratepayers (Attorney General Reply Brief at 23).

Based on the foregoing, the Attorney General asserts that the Department should: (1) make no changes to the current GBE Tracker approved in D.P.U. 17-170; (2) reject the Company's request to increase the amount of non-recurring O&M costs recovered through base distribution rates from $1.47 million to $7.89 million; and (3) reject the Company's proposal to transition GBE program costs to base distribution rates as part of the Company's annual PBR adjustment filing to take effect on October 1, 2023 (Attorney General Reply Brief at 23-24).

b. Company

National Grid argues that its proposed modifications to the GBE cost recovery structure approved in D.P.U. 17-170 should be approved (Company Reply Brief at 29). The Company argues that its proposal to increase the amount recovered through base distribution rates from $1.47 million to $7.89 is reasonable, reflects the actual test-year level of non-recurring costs expenses, and is consistent with the Department's finding in D.P.U. 17-170 that such cost recovery is appropriate (Company Reply Brief at 29-30, citing

D.P.U. 17-170, at 243-244). The Company contends that the critical issue is that the need for base distribution rate recovery has not changed from its last base distribution rate case, but rather only the amount of test-year expenses has changed (Company Reply Brief at 30-31, citing Exh. NG-ITP-1, at 19; D.P.U. 17-170, at 243-44). National Grid dismisses the Attorney General's argument that GBE costs vary from year to year, and notes that such fluctuation is the reason why the Department established a "two-pronged" recovery structure that allows for certain costs to be recovered through base distribution rates and other costs to be recovered through the GBE Tracker (Company Reply Brief at 31-32).

National Grid also argues that the Attorney General has misstated the status of the GBE deployment and the Company takes issue with the Attorney General's claim that the future of the GBE program is uncertain (Company Reply Brief at 31, citing Attorney General Brief at 20-22). National Grid concedes that both the implementation timeline and costs associated with the GBE program have been adjusted due to various factors, including the COVID-19 pandemic and roll-out issues in Rhode Island and New York (Company Brief at 334-341, 348-350, citing Exhs. NG-ITP-1, at 23; DPU 31-5; DPU 35-1 & Supp.; DPU 35-2 (Supp.)). In particular, the Company notes that it re-sanctioned the GBE program in December 2020, which resulted in a nearly $200 million increase in budget (Company Brief at 348, citing Exh. DPU 35-2 (Supp.)). National Grid, however, also contends that the program's reorganization increased the GBE program's value by $120 million (Company Brief at 348-350, citing Exh. DPU 35-2 (Supp.); Company Reply Brief at 31-32). Further, in response to the Attorney General's claims regarding the uncertainty of the GBE program, National Grid argues that an internal reorganization of the Company's IT department will have a positive impact on the GBE Program by clarifying program governance, roles and responsibilities, and accountability for program delivery and performance achievement (Company Brief at 350-351, citing Exh. DPU 53-6).

The Company also maintains that full deployment of the GBE program in Massachusetts is expected in May 2022 (Company Brief at 334, 340-341, 343-346). In this regard, National Grid contends that through implementing lessons learned from rollouts prior to the Massachusetts deployment date, the Company expects to minimize system fixes and workarounds that occurred previously in other service areas, while streamlining the GBE Program rollouts in the long term (Company Brief at 336, citing Exh. DPU 21-7). National Grid also argues that the changes in the deployment timeline have not impacted the underlying need for, or the benefits of, the GBE program (Company Brief at 342-343). In particular, National Grid contends that moving the Massachusetts deployment date to May 2022: (1) reduces implementation risks; (2) improves the quality of the functionality and data available at the Go Live date; (3) allows for the development and testing of critical interfaces with the legacy customer back-office systems supporting Massachusetts; (4) provides time and resources for continuous improvement of the deployed solution; (5) allows the GBE program team to monitor the stability and performance of the GBE program solution, with particular focus on deployed new functionality; and (6) avoids major system deployments during the home heating season, which mitigates the risk to customers of potential system disruptions impeding field operations and customer service during periods of inclement weather (Company Brief at 344-348, citing Exh. DPU 35-2).

Finally, the Company argues that its proposal to terminate the GBE Tracker and transition costs into base distribution rates, effective October 1, 2023, is appropriate (Company Reply Brief at 33). The Company notes that the GBE Tracker was designed as a temporary mechanism effective only through the implementation of the GBE program (Company Reply Brief at 34). As such, the Company argues that continuation of the GBE Mechanism after the Go Live date is inconsistent with the design of the GBE Mechanism, and that the costs associated with the GBE program on an ongoing basis are O&M costs that are appropriately collected through base distribution rates (Company Reply Brief at 34). Further, the Company asserts that incorporating the GBE program costs into the Company's base rates is also consistent with Department precedent (Company Reply Brief at 34, citing D.P.U. 94-158, at 58-64).

4. Analysis and Findings

As noted above, the Company proposes to continue the special ratemaking treatment approved in D.P.U. 17-170, with several modifications, until the GBE program is fully implemented in Massachusetts (Exh. NG-ITP-1, at 24-25). The record shows that the implementation of the GBE program in Massachusetts has encountered delays and the costs associated with the program have increased over time (see, e.g., Exhs. NG-ITP-1, at 22-23; DPU 31-5, at 2-3; DPU 35-1; DPU 35-2, at 5 (Supp.); DPU 35-3 & Atts.; DPU 53-4, Att. at 181). In particular, the Go Live date has been extended twice since the Company's last base distribution rate case and now is anticipated, though not confirmed, to be in May 2022 (Exhs. NG-ITP-1, at 7, 22-23, 25; DPU 31-5, at 2; DPU 35-1; DPU 35-3; see also n.135 above). Further, in December 2020, the program was re-sanctioned and the program's budget was increased by $196.8 million to $675.1 million (Exhs. DPU 35-1 (Supp.); DPU 35-2, at 5 (Supp.); DPU 53-3; DPU 53-7). Additionally, the Department notes that a recent management audit raised concerns about the potential impact on the GBE program from major reorganizations at National Grid USA, including leadership changes in the IT department (Exh. DPU 53-4, Att. at 181).

The Department acknowledges the Company's responses to these developments. For instance, we recognize that some of the deployment delay for Massachusetts was caused by roll-out issues in Rhode Island, a seven-month deferral of the Upstate New York release, and the implementation of COVID-19 restrictions in March 2020 (Exhs. NG-ITP-1, at 22-23; DPU 35-1 (Supp.)). Further, National Grid has outlined a number of ways in which it maintains that Massachusetts ratepayers will benefit from the current deployment schedule, as the deployment delay has allowed the Company to further evaluate and enhance a number of components of the GBE program (Exhs. DPU 21-7; DPU 35-2). The Company also provided evidence that the December 2020 re-sanctioning of the GBE program budget resulted in a higher value for the GBE program (Exh. DPU 35-2, at 5-7 (Supp.)). Additionally, the Company maintains that internal reorganizations will have a positive impact on the GBE program by clarifying program governance, roles and responsibilities, and accountability for program delivery and performance achievement (Exh. DPU 53-6).

In D.P.U. 17-170, at 240, the Department found that National Grid's GBE program was necessary to improve the efficiency and effectiveness of the Company's operations, which would improve customer experiences and promote a safer and more reliable natural gas infrastructure. Based on our review of the record in the instant proceeding, we continue to find that the GBE program is a necessary part of the Company's business and, when fully implemented, will have positive impacts on customer experience and the Company's infrastructure (Exhs. DPU 21-7; DPU 31-5; DPU 35-2 & Supp.; DPU 35-3 & Atts.; DPU 35-4 & Att.; DPU 53-6). Nevertheless, based on the delay in the Massachusetts deployment of the GBE program and the significant cost increases of the program, we conclude that the special ratemaking treatment approved in D.P.U. 17-170 needs to be refined to reflect a more appropriate balance between the Company's need to recover necessary costs associated with the GBE program and the Department's interests in ensuring regulatory oversight and limiting ratepayer risk.

In establishing the GBE Tracker in D.P.U. 17-170, the Department noted several advantages to the reconciling mechanism, including providing necessary protections for ratepayers by limiting the Company's revenue collection to the actual expenses incurred, ensuring Department and intervenor oversight before costs may be recovered, and passing through any known and measurable savings to ratepayers annually, rather than waiting until new base distribution rates are put into effect. D.P.U. 17-170, at 241-242. Given the deployment and cost issues discussed above, the advantages of a cost tracker are even more important now. As such, we conclude that, at this time, it is appropriate to move all cost recovery associated with the GBE program into the GBE Tracker.[139]

We decline to allow the Company to continue recovery of non-recurring labor costs through base distribution rates and to increase the amount of such costs from $1.47 million to $7.89 million (Exhs. NG-ITP-1, at 19; DPU 21-2, Att.; DPU 21-3; DPU 39-1). These "one-time labor costs" have increased more than 436 percent since the Company's last base distribution rate case. Further, despite the Company's position that Massachusetts ratepayers will benefit from the deployment delay once the program is fully implemented, we are concerned that these benefits have been slow to materialize and that ratepayers have received no definitive benefits to date, despite paying for GBE-related costs through base distribution rates (Exh. DPU 35-2).[140] Additionally, the Company has provided expectations, but no assurances, that full implementation of the GBE program in Massachusetts (i.e., the Go Live date) will occur in May 2022 (Exhs. NG-ITP-1, at 22-23, 25; DPU 31-5, at 2; DPU 35-1; DPU 35-3). Thus, there still exists some uncertainty of when base distribution rate recovery would end under the Company's proposal.

---

139 The Attorney General raised concerns regarding the interplay of cost recovery mechanisms and the PBR (Attorney General Brief at 19). The Department addresses this issue in Section IV.D.6 above.

140 In approving GBE-related cost recovery, the Department noted that to the extent we approve costs that are later found to provide minimal or no benefit to ratepayers, the Department reserves the right to remedy this deficit through appropriate regulatory actions. D.P.U. 17-170, at 247.

Typically, non-recurring expenses incurred during the test year are ineligible for inclusion in the cost of service unless it is demonstrated that they are so extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. D.P.U. 1270/1414, at 33. The Company has not made such a demonstration. Rather, the Company simply relies on the Department's previous decision in D.P.U. 17-170 to justify the continued recovery of these costs (Company Reply Brief at 29-30, citing D.P.U. 17-170, at 243-244). In D.P.U. 17-170, however, the Department carved out a limited exception to allow recovery of the one-time labor costs through the cost recovery structure approved in that case based on the circumstances of the GBE program at that time. D.P.U. 17-170, at 243. The Department did not change our long-standing precedent that standard for non-recurring costs. D.P.U. 17-170, at 243. In light of the foregoing considerations and based on the status of the GBE program in Massachusetts, we conclude that the continued recovery of GBE-related implementation costs in base distribution rates is no longer appropriate.

As noted, the Company also proposes to continue the GBE Tracker until the October 1, 2023, at which time it would move all GBE-related costs into base distribution rates through an adjustment to the PBR and terminate the tracker (Exhs. NG-ITP-1, at 18-20, 25; DPU 21-3; DPU 50-6). Given the considerations and findings above, we decline to approve any transition of costs to base distribution rates at this time. Thus, the Company's GBE Tracker shall continue until the Company's next base distribution rate case. At the time of National Grid's next base distribution rate case, the Company may submit a proposal for transitioning the ongoing GBE-related costs from the GBE Tracker to base distribution rates. As discussed in Section IV.D above, the Department has approved a PBR plan with a five-year stay-out provision. Thus, we recognize that the Company cannot file a base distribution rate case during the PBR term that would result in new base distribution rates going into effect earlier than October 1, 2026 (Exh. NG-PBRP-1, at 28 (Rev.)). At the time of the Company's next base distribution rate case, however, we expect that the GBE program will be fully implemented, and the Company will be able to propose a representative amount of known and measurable ongoing GBE-related costs to be included in base distribution rates.

In the meantime, the costs to be recovered through the GBE Tracker will be limited to the actual labor costs to implement the program, annualized rent expense allocated to the Company, and the costs that the Company incurs to support the GBE system architecture and operations through the Go Live date and beyond (Exh. NG-ITP-1, at 18-20). The Company shall continue to file annual GBE rate adjustment and reconciliation filings consistent with our directives in D.P.U. 17-170, at 245-248. Further, the Department finds that the Company's GBE program cost allocators remain an appropriate method to allocate the costs that NGSC incurs (Exh. NG-PP-10, proposed M.D.P.U. No. 3.13, §§ 6.13(9), 6.14). In addition, consistent with our findings in D.P.U. 17-170, at 245-246, to preserve regulatory lag, National Grid shall not accrue interest on investments during the time period between when the Company incurs the costs and when the Company recovers the costs through rates. The Company, however, shall accrue interest on over- and under-recoveries of the revenue requirements (i.e., the reconciliation component). D.P.U. 17-170, at 246.

As part of the annual filings, the Company shall continue to provide testimony and supporting exhibits, including full project documentation for NGSC's GBE capital projects placed into service during the prior year, as well as documentation supporting expenses sought for recovery. Specifically, the annual filings shall continue to contain testimony and supporting documentation demonstrating that costs sought for recovery are prudently incurred and used and useful.[141] The Company also must continue to provide testimony in their annual filing that shows the benefits NGSC's investments have made on behalf of ratepayers, consistent with our directives in D.P.U. 17-170, at 247-248. Further, National Grid shall continue to provide bills that NGSC renders to the Company or other documentable evidence supporting the Company's incurred costs associated with GBE rent expense.

By allowing recovery of all of the GBE-related costs into the GBE Tracker, the Company will earn dollar-for-dollar recovery of actual GBE-related investments in between base distribution rate cases, ratepayers will receive necessary protections and cost savings during and after the implementation of the GBE program, and the Department will retain appropriate regulatory oversight. The Department directs the Company to modify the GBE section of the proposed LDAC tariff for Department review, consistent with the directives contained herein (Exh. NG-PP-10, proposed M.D.P.U. No. 3.13, §§ 6.13(9), 6.14).

---

[141] The Department further directs the Company to fully document and explain all implementation delays and cost over-runs for GBE program investments when seeking cost recovery.

Finally, because we have removed GBE-related costs from base distribution rates, the Company's proposed cost of service needs to be adjusted. Accordingly, the Department will reduce the Company's proposed cost of service by $7,887,387. The effect of this adjustment is shown in Schedule 2 below.

D. Joint Facilities Rent Expense

1. Introduction

Joint facilities are facilities owned by the Company's affiliates that the Company uses in providing service to customers (Exh. NG-RRP-1, at 49). The Company's joint facilities rate year rent expense is intended to recover capital assets, O&M expenses, and property tax expense related to affiliate-owned facilities (Exhs. NG-RRP-1, at 49; DPU 13-9, DPU 13-10). The Company presently occupies space and is allocated costs at intercompany facilities located in Northboro, Beverly, Malden, Leominster, Millbury, and Northbridge, Massachusetts (Exhs. NG-RRP-2, Sch. 18, at 4 (Rev. 3); DPU 13-3). The Company also occupies space and is allocated costs at an intercompany facility in Syracuse, New York, which is owned by Niagara Mohawk Power Corporation ("NMPC") (Exhs. NG-RRP-2, Sch. 18, at 4 (Rev. 3); DPU 13-3).

During the test year, the Company booked $4,593,017 in joint facilities rent expenses (Exhs. NG-RRP-1, at 49; NG-RRP-2, Sch. 18, at 1, 4 (Rev. 3); DPU 13-1). The Company proposed a normalizing adjustment of $282,341 related to a correcting adjustment made during the test year for certain intercompany facilities, which resulted in an adjusted test-year level of expense of $4,875,357 (Exhs. NG-RRP-1, at 49; NG-RRP-2, Sch. 18, at 1, 4

(Rev. 3); DPU 13-1; DPU 13-3; AG 2-22). Included in the normalizing adjustment amount was $4,672 for an intercompany rent airplane upgrade (Exhs. NG-RRP-2, Sch. 18, at 4 (Rev. 3); DPU 43-1; DPU 43-2; DPU 43-3; AG 13-4).[142]

2. Positions of the Parties

On brief, the Company summarizes its proposed adjustments to joint facilities expense (Company Brief at 123). No intervenor addressed this issue on brief.

3. Analysis and Findings

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

142 The Company states that costs associated with an aviation upgrade project that went into service October 2019 were not properly allocated, and it would have been charged $4,672 in the historical test year had the cost of this project been allocated properly (Exhs. DPU 43-1; AG 13-4).

As noted above, no intervenor has challenged the Company's proposed joint facilities expense. Based on our review of the record, we are satisfied that the costs allocated to the Company and paid to its affiliates are for activities that benefit the Company and do not duplicate services already provided by the Company (Exhs. DPU 13-1; DPU 13-3; DPU 13-10; AG 2-24; AG 2-25; AG 2-28; AG 2-29). Further, the Company has provided the Department with a breakdown of the costs incurred and joint facilities rental agreements (Exhs. NG-RRP-2, Sch. 18 (Rev. 3); DPU 13-1; DPU 13-2; DPU 13-4; AG 2-23 through AG 2-29).

The Department, however, finds that the Company erroneously calculated the portion of adjusted test-year expense attributable to the Syracuse facility of $972,116 using a pre-tax WACC of 10.69 percent (Exhs. NG-RRP-2, Sch. 18, at 4 (Rev. 3); DPU 13-1, Att. 2, at 27). Instead, National Grid should have applied the Company's pre-tax WACC to the Syracuse facility expense. D.P.U. 18-150, at 257. In Section XII.B.3 and Section XII.C.4 below, the Department approved a ROE of 9.70 for the Company and a capital structure of 46.56 percent long-term debt and 53.44 percent common equity. Using the ROE and capital structure approved in this proceeding yields an overall WACC of 6.98 percent and a pre-tax WACC of 8.93 percent. Applying the Company's approved 8.93 percent pre-tax WACC instead of 10.69 percent results in a joint facilities expense of $826,962 for the Syracuse facility (see Exh. DPU 13-1, Att. 2, at 27). Accordingly, we decrease the Company's adjusted test-year-end joint facilities expense for the Syracuse facility by $145,154 ($972,116 - $826,962). The Department similarly adjusts downwards the Company's rent airplane upgrade expense by $921[143] based on the application of the pre-tax WACC of 8.93 percent. The Department, therefore, disallows a total of $146,075[144] for joint facilities rent expenses. As a result of the adjustments for the joint facilities expense, inflation expense will be updated in Schedule 2A below.

E. Service Company Rents Expense

1. Introduction

NGSC maintains and manages the computing infrastructure relied on to provide electric and gas distribution service across all of National Grid USA's service territories (Exh. NG-ITP-1, at 8). In addition, NGSC delivers innovative solutions to National Grid USA's business functions in support of the overall business strategy of each operating affiliate, including the Company (Exh. NG-ITP-1, at 8). The services provided by NGSC to the Company range from the support of critical gas distribution IT-related systems to the support of standard office desktop applications (Exh. NG-ITP-1, at 8).[145] The Company

---

143 The Department based its calculation on the percentage difference of a pre-tax WACC of 10.69 percent and the Department's calculated pre-tax WACC of 8.93 percent applied to the Company's proposed rent airplane upgrade expense (see Exh. DPU 43-2). By calculation: ($4,672*((0.1069-0.0893)/0.0893)).

144 Total joint facilities disallowances: $145,154 for Syracuse facility + $921 for rent airplane upgrade = $146,075.

145 The core IT services provided by NGSC are: (1) strategy and planning, which includes management oversight and support for the delivery of IT service to the business; (2) end-user services, which are commodity-based services consumed by the office and field end-users and include laptops, iPads, communication and collaboration tools, connectivity, and print services; (3) service management, which includes IT service desk and on-site help desks; (4) Critical National Infrastructure applications and services; (5) infrastructure support, which includes disaster recovery, incident

states that these services are necessary to enable the safe, reliable, and physically secure commercial operation of the Company (Exh. NG-ITP-1, at 8).

IT capital projects and investments that are shared across operating companies are implemented and owned by NGSC and allocated to the Company in the form of an annual rent expense ("service company rents"), and the costs of NGSC IT capital projects are depreciated, amortized, and recovered over a period of years determined by the average service lives of the IT assets (Exh. NG-ITP-1, at 13-14). Software-related IT projects typically are amortized over a period of 84 months, while hardware and equipment typically are amortized over a period between 36 and 60 months (Exh. NG-ITP-1, at 14). The allocation of IT project costs is determined by applying specific cost allocation codes to assign rent expense based on cost causation and an allocation of costs to each operating company that derives a benefit from the investment (Exhs. NG-ITP-1, at 14; NG-ITP-4; DPU 13-13; AG 1-92). The allocated rent expense is comprised of amortization/depreciation expense, and a service company return component, which is based on the Company's capital structure and return on equity (Exhs. NG-RRP-2, Sch. 1, at 6 (Rev. 3); DPU 13-6).

support, storage, back-up, and archive of data; (6) network, which includes wide area network, local area network, voice network, internet, and remote access services; (7) IT security, which includes but is not limited to cyber security, platform security, network security, physical security, and technology risk management; (8) application support, which includes licensing for applications needed to support the business and includes maintenance and upgrades; and (9) IT project investments (Exh. NG-ITP-1, at 8-9).

2. Company Proposal

During the test year, NGSC charged National Grid $17,115,315 in service company rents categorized as asset recovery charges (“ARCs”) (Exhs. NG-RRP-1, at 46; NG-RRP-2, Sch. 17, at 1, 4 (Rev. 3); DPU 13-8).[146] National Grid proposed a normalizing adjustment of negative $1,004,156 to restate the allocation of service company rents based on a true-up of the return-on and return-of capital calculations for those charges, which resulted in a normalized test-year service company rent expense of $16,111,159 (Exhs. NG-RRP-1, at 47; NG-RRP-2, Sch. 17, at 1, 2, 4 (Rev. 3); WPs NG-RRP-6a; NG-RRP-6b). The Company then proposed the following adjustments to increase its adjusted test-year service company rent expense by: (1) $2,650,419 to account for ongoing depreciation and return on existing IT and facilities assets, as well as anticipated IT system additions and enhancements and facilities improvements that will be in-service by March 31, 2021; and (2) $1,849,116 to account for incremental rate year IT “run-the-business” costs, such as annual Microsoft licenses, data center renewal contracts, GPS mapping licenses, service licenses, and mainframe upgrade costs (Exhs. NG-RRP-1, at 46-47; NG-RRP-2, Sch. 17, at 3-5 (Rev. 3);

---

146 ARC service company rent expense represent fees for assets owned by NGSC and used to provide services to the operating companies. The ARCs are comprised of four items: (1) ARC-Depreciation, which represents the depreciation expense associated with each service company information system and facility project charged to the Company during the test year; (2) ARC-Debt, which represents the allocation of the return component of the service company rent expense; (3) ARC-Equity, which represents the allocation of the return component of the service company rent expense; and (4) ARC-Property Tax, which represents the personal property taxes paid by NGSC on the December 31, 2018 net book value of its Massachusetts assets (Exhs. NG-RRP-2, Sch. 17, at 4 (Rev. 3); DPU 13-8).

WPs NG-RRP-6c through NG-RRP-6f; DPU 21-8). The adjustments result in a proposed rate year service company rent expense of $20,610,694 (Exh. NG-RRP-2, Sch. 17, at 2 (Rev. 3)).

In addition to the vendor costs noted above, the Company's proposed rate year cost of service includes costs associated with 114 IT projects completed between January 1, 2017 and the end of the test year, March 31, 2020, and costs associated with 67 IT projects completed after the end of the test year and through March 31, 2021 (Exhs. NG-ITP-1, at 6; NG-ITP-1, at 4-5 (Supp.); NG-ITP-5, Att. 1; NG-ITP-6, Att. 1 & Supp.; DPU 39-3 & Atts.). The Company states that it provided all necessary documentation to support the proposed cost recovery related to its IT projects and vendor costs (Exhs. NG-ITP-1, at 6, 14-17; NG-ITP-5 through NG-ITP-7).

Further, the Company's filing includes "introductory information" about two significant IT projects that NGSC has commenced work on, but which will not be implemented for several years (Exh. NG-ITP-1, at 7). The first IT project is intended to replace the Company's current legacy CIS to provide an integrated, modern, and flexible system to support business and customer needs (Exh. NG-ITP-1, at 26). The second IT project - referred to as "SAP S/4 HANA" - will exist as a back-office platform to support functions such as finance, payroll, human resources, and supply chain (Exh. NG-ITP-1, at 26). National Grid is not requesting cost recovery in this proceeding for these projects, but the Company states that there are implications associated with project implementation that will need to be considered in conjunction with the proposed PBR plan (Exh. NG-ITP-1, at 7).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that the total IT rent expense claimed by the Company in this proceeding exceeds the rate year total IT rent expense of $10.7 million allowed by the Department in the Company's last base distribution rate case (Attorney General Brief at 116, citing Exhs. NG-ITP-1, at 16; NG-RRP-2, Sch. 17, at 4; D.P.U. 17-170, at 203). While the Attorney General claims that total IT costs are significant in the aggregate, she does not allege that the spending level is unreasonable given the "challenging and problematic" initial state of the Company's IT platform, which she describes as ineffective for a period of years (Attorney General Brief at 117-118, citing Exhs. AG-DAL-1, at 4-5; AG-BM-1, at 5; DPU 53-4, Att.). The Attorney General also notes that National Grid's anticipated IT spending to replace the CIS program appears to be reasonable, but she cautions that tight, coordinated planning is essential to a successful rollout of the replacement systems (Attorney General Brief at 117).

Further, the Attorney General notes that the Company's "IT Operating Model Playbook," which describes the governance, control, roles, and responsibilities of the IT Group, appears to be "generally suitable" for an organization of National Grid's size and scope (Attorney General Brief at 117-118, citing Exh. AG-BM-1, at 5). Similarly, the Attorney General claims that the Company's "IT Strategy and Strategic Business Plans" are "conceptually strong and a foundation for a successful IT organization" (Attorney General Brief at 118).

The Attorney General does not propose any specific cost disallowances related to the Company's IT expense. The Attorney General, however, does offer several recommendations. First, the Attorney General asserts that National Grid should place greater emphasis on supporting end-of-life business applications, operating systems, and hardware (Attorney General Brief at 118, citing Exh. AG-BM-1, at 6-7). Second, the Attorney General recommends that the Company should strive to defer discretionary IT projects wherever possible in order to mitigate the overall rate impact of IT project costs, as well as the workload impacts of IT personnel and related business operations resources (Attorney General Brief at 118, citing Exh. AG-BM-1, at 7). Third, the Attorney General recommends that the Company internalize and "put into full effect" the governance and controls described in the Company's IT Operating Model Playbook and the IT Strategy and Strategic Business Plan as a means of maintaining capable, stable, supported, secure IT systems (Attorney General Brief at 119, citing Exh. AG-BM-1, at 7).

Next, the Attorney General contends that 43.4 percent of the Company's test-year IT projects were delivered on time when compared to the originally planned in-service dates (Attorney General Brief at 119, citing Exh. AG-BM-1, at 11). The Attorney General, however, notes that the Company's in-service performance improved for post-test-year IT projects (Attorney General Brief at 119, citing Exh. AG-BM-1, at 11). The Attorney General attributes the post-test-year in-service improvement to the Company appropriately focusing on key performance indicators ("KPI") to improve performance (Attorney General Brief at 119-120). The Attorney General asserts, therefore, that the Company should continue to focus on the KPIs to ensure more projects are delivered on time going forward (Attorney General Brief at 120).

Finally, the Attorney General argues that, based on a sample of six test-year IT projects, the Company was unable to provide hard evidence of direct, measurable benefits (either in cost savings or measurable service improvements) for five of the six projects (Attorney General Brief at 120, citing Exhs. NG-ITP-Rebuttal-1, at 12; AG-BM-1, at 13-24; AG 25-4). The Attorney General asserts that such difficulty in quantifying specific IT project benefits leads to discretionary IT investments driven by indirect benefits that cannot be measured or verified (Attorney General Brief at 120, citing Exhs. AG-BM-1, at 25-26; DPU 53-4, Att. at 148-149). Accordingly, the Attorney General recommends that the Company continue its efforts to improve the quantification of benefits, improve the benefits definition in its discretionary investment business case, and establish a more robust process to track benefits going forward (Attorney General Brief at 120-121, citing Exh. NG-ITP-Rebuttal-1, at 12-14).

b. Company

On brief, the Company summarizes the status of its IT structure, project planning and development, cost allocation process among the various National Grid USA affiliates, and its cost recovery of IT investments (Company Brief at 107-110, citing Exhs. NG-ITP-1, at 8-11, 13-14; NG-ITP-4; DPU 13-13; AG 1-92; AG 14-5 & Att. 1). Further, the Company asserts that it provided requisite supporting documentation for all capital IT projects placed into service between January 1, 2017 and the end of the test year in this proceeding, March 31, 2020, as well as all post-test-year IT projects (Company Brief at 110-111, citing Exhs. NG-ITP-1, at 14-15; NG-ITP-5; NG-ITP-6-(Supp.); DPU 57-1; DPU 57-2 & Att.; DPU 57-5 & Att.). Further, the Company argues that Department recognition of post-test-year IT project costs is both reasonable and appropriate, as the investments are known and measurable and were either in service at the time of the Company's filing or were placed in service by March 31, 2021 (Company Brief at 112, citing Exh. NG-ITP-1, at 17).

In response to the Attorney General's recommendations, first, National Grid asserts that it is actively supporting end-of-life IT business applications by monitoring and measuring technical debt and the existence of IT assets that are operating at or beyond their useful lives (Company Brief at 196, citing Exh. NG-ITP-Rebuttal-1, at 5). National Grid claims that since its Technology Modernization program began in 2016, end-of-life unsupported infrastructure (i.e., server hardware, server software, network devices, and end-user devices) has reduced from 76.5 percent to 37 percent in the U.S. (Company Brief at 196, citing Exh. NG-ITP-Rebuttal-1, at 5). Further, National Grid states that the organization's goal is to reduce the unsupported end-of-life infrastructure to 15 percent over the next two years, which the Company claims would achieve a normal, ongoing, and recurring level of IT investment (Company Brief at 196, citing Exh. NG-ITP-Rebuttal-1, at 5). The Company asserts that it is prioritizing these IT matters according to security, operational, and financial risk and that the program is proceeding at its scheduled pace (Company Brief at 196).

Second, the Company disagrees with the Attorney General's recommendation to defer discretionary IT projects whenever possible (Company Brief at 197). The Company argues that deferring discretionary IT projects is neither necessary nor in the best interest of the Company's customers (Company Brief at 197). Rather, the Company contends that an IT investment requires a balanced mix of both discretionary and non-discretionary IT investments (Company Brief at 197). For example, the Company notes that its fiscal year 2022 ("FY 22") IT investment plan has an "approximately 60/40 split" between non-discretionary investments such as technical debt remediation, cyber/physical security and regulatory mandates, and discretionary investments such as digital investments that are enabling productivity and efficiency improvements and investments in grid modernization and clean energy (Company Brief at 197, citing Exh. NG-ITP-Rebuttal-1, at 7-8).

Third, the Company addresses the Attorney General's recommendation that the Company continue to use KPIs to ensure more IT projects are completed on time (Company Brief at 198). The Company disagrees with the Attorney General's calculation method that finds only 43.4 percent of the Company's test-year IT projects were placed in service on time (Company Brief at 198). Specifically, the Company explains that the on-time percentage completion used by the Attorney General was a comparison of the estimated IT in service date at the time of the full project sanction (which could be months or years into the future depending on the size and complexity of the IT project) and the actual in-service date at the time the project was used and useful to customers (Company Brief at 198, citing Exh. NG-ITP-Rebuttal-1, at 11). Thus, the Company asserts that the Attorney General's calculation method was based on the actual project delivery (on a pass/fail basis) at or before the estimated in-service date with no consideration of projects that went into service after the estimated in-service date (even by a week), which would have otherwise resulted in a higher on-time percentage of test-year IT projects and would have still delivered the expected project benefits to customers (Company Brief at 198, citing Exh. NG-ITP-Rebuttal-1, at 11). The Company notes that it uses the Baseline Execution Index ("BEI"), an industry standard metric, to track how closely an IT project is executing in real time (Company Brief at 198, citing Exh. NG-ITP-Rebuttal-1, at 11). The Company explains that an IT project is baselined at every sanction point and, if an unforeseen event occurs (i.e., storm, pandemic) that adversely affects the project schedule, a re-baseline can be performed, provided certain approvals are provided (Company Brief at 198, citing Exh. NG-ITP-Rebuttal-1, at 11). Further, the Company claims that its senior leadership reviews on a monthly basis the BEI for IT projects, with a focus on IT projects that are in an alert state based on the BEI score (Company Brief at 199, citing Exh. NG-ITP-Rebuttal-1, at 12). The Company notes that, for 114 IT projects that were either delivered in fiscal year 2021 or in progress and actively monitored under BEI, 95 percent were classified as "On Time Performance as of March 31" and 94 percent were "On Cost Performance as of March 31" (Company Brief at 199, citing Exh. NG-ITP-Rebuttal-1, at 12).

Next, National Grid takes issue with the Attorney General's contention that the Company failed to show benefits associated with five of six sample test-year IT projects (Company Brief at 199, citing Attorney General Brief at 121). According to the Company, benefits were achieved on all six sample IT projects and the investments are benefitting the Company's customers (Company Brief at 199, citing Exh. NG-ITP-Rebuttal-1, at 13). The Company notes, however, that it has taken steps to improve upon the definition of "benefits" in the new business case process developed in 2020 (Company Brief at 199, citing Exh. NG-ITP-Rebuttal-1, at 13). Further, the Company notes that it has established a new business case process for discretionary IT programs/investments as it relates to the quantification of monetary benefits and cost avoidance (Company Brief at 199, citing Exhs. NG-ITP-Rebuttal-1, at 14; AG 14-5).[147] Additionally, the Company asserts that it is currently developing a process for tracking the benefits of the IT project/investment (Company Brief at 200, citing Exhs. NG-ITP-Rebuttal-1, at 14; AG 14-5).

Finally, the Company summarizes the information surrounding the planned replacement of the CIS program and the anticipated SAP S/4 HANA project (Company Brief at 113-122). For both projects, the Company asserts there will be impacts to the overarching cost structure (both upward and downward) that will need to be accommodated in the future through the Department's ratemaking process (Company Brief at 122, citing Exh. NG-ITP-1, at 38). Thus, the Company states that it provided information on its future IT projects to

---

147 In particular, the Company explains that the discretionary IT programs/investments are assigned a priority level after it has weighed the benefits, business criticality, alignment to strategic initiatives, regulatory compliance, business readiness, and delivery complexity (Company Brief at 199). As part of the process, the Company states that it must receive sign-off from its business and IT stakeholders who would have impact on costs and benefits (Company Brief at 199).

give perspective on future plans that will impact the Company's IT project cost structure (Company Brief at 122).

4. Standard of Review

The standard for the inclusion of IT expense is comprised of three elements.[148] First, the investments underlying the IT expense must be and used and useful. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Second, the underlying IT investments must be prudently incurred. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Third, the underlying IT investments must be fairly allocated to the company, with an explanation of how the company and its ratepayers benefit from the investment. D.P.U. 18-150, at 274-275, citing Hingham Water Company, D.P.U. 88-170, at 21 (1989); Housatonic Water Works Company, D.P.U. 86-93, at 18 (1987); see also D.P.U. 12-86, at 11 (the Department must carefully scrutinize affiliate transactions because the exercise of control and the absence of arm's-length bargaining between affiliated companies can lead to "excessive charges for services, construction work, equipment and materials") (citations omitted); Public Utility Holding Company Act of 1935, P.L. No. 333, 49 Stat. 803, § 1(b)(2), (3) (1935)

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

(Congress recognized concern with allocation of costs within public utility holding company as reason for legislative/regulatory control of holding companies where subsidiary company accounting practices and rates are affected); Report of the Special Commission on Control and Conduct of Public Utilities (1930 H. 1200), at 46 (March 1930) (consumers suffer from excessive charges by affiliates to operating companies).

In addition, as part of their initial filings requesting new base distribution rates, petitioning companies must submit the following documentation for each service-company-allocated IT investment: (1) project sanctioning papers; (2) project closure reports; (3) variance analyses explaining the reasons for cost overruns and for demonstrating prudency; (4) project descriptions, including completed analyses enumerating ratepayer benefits and the investment's advancement of company IT strategy; and (5) the company's long-term investment plan. D.P.U. 18-150, at 275. Petitioning companies are also required to seasonably amend their initial filings to include documentation associated with post-test-year investments, if applicable. D.P.U. 18-150, at 275.

5. Analysis and Findings

a. Test-Year and Post-Test-Year IT Projects

The Department has reviewed the testimony and documentation provided by the Company in its initial filing concerning the test-year and post-test-year IT projects, as well as the post-test-year vendor costs. The Department finds that the Company provided requisite project documentation for all projects and costs, as well as updates for post-test-year investments in accordance with the filing requirements established in D.P.U. 18-150 (see, e.g., Exhs. NG-ITP-1, at 6, 14-15; NG-ITP-1, at 4-5 (Supp.); NG-ITP-5 through NG-ITP-7; NG-ITP-6 (Supp.); NG-RRP-2, Sch. 17 (Rev. 3); WPs NG-RRP-6a through NG-RRP-6f; DPU 39-3 & Atts.; DPU 57-1 through DPU 57-6).[149]

As noted above, National Grid proposes a rate year service company expense of $20,610,694, consisting of an allocated amount of depreciation/amortization expense and a return component for test-year and post-test-year information systems projects and facilities (Exhs. NG-RRP-2, Sch. 1, at 6 (Rev. 3); NG-RRP-2, Sch. 17, at 2 (Rev. 3); DPU 13-6). In deriving the return component, National Grid uses a capital structure of 46.56 percent long-term debt and 53.44 percent common equity and the Company's proposed 10.5 percent ROE (Exhs. NG-RRP-2, Sch. 1 at 6 (Rev. 3); AG 22-2).

The Department finds it appropriate to use the capital structure approved in this proceeding, which is the same capital structure as proposed by the Company – 46.56 percent long-term debt and 53.44 percent common equity, as determined in Section XII.B.3 below. We also find that the use of the petitioning company's approved ROE in calculating a return

---

[149] In SectionVIII.H.3.b below, the Department disallowed the lease expense associated with the relocation of the MetroTech Center facility in Brooklyn, New York to 2 Hanson Place. Based on our review of Exh. WP NG-RRP-6f compared to Exh. WP NG-RRP-6f (Rev. 2), it appears that the Company's facilities expense does not contain costs associated with this relocation (see Exhs. WP NG-RRP-6f, line 8 (forecasted Brooklyn, NY Office Relocation, workorder number 90000191056); Exh. WP NG-RRP-6f (Rev. 2) (the investment name "Brooklyn, NY Office Relocation" and workorder number "90000191056" do not appear in the updated workpaper); AG 43-4. Therefore, our findings in the instant section should not be read as any acknowledgment that 2 Hanson Place facility is currently in use and providing benefits to Massachusetts ratepayers.

component of capital charges by an affiliated company[150] is appropriate and consistent with Department precedent. D.P.U. 17-05, at 165-166; D.P.U. 15-155, at 303-304. Thus, we apply the ROE of 9.70 percent allowed in Section XII.C.4 below. Based on the foregoing, for the return component of the Company's service company rent expense, the Department calculates the WACC using the capital structure and ROE approved in this Order. Using the capital structure and ROE approved in this proceeding produces an overall WACC of 6.98 percent and a pre-tax WACC of 8.93 percent. Application of the Company's approved pre-tax WACC to NGSC's allocation of service company rent expense results in a decrease of $237,651 to the rate year service company rent expense. Accordingly, the Department decreases the Company's proposed service company rent expense by $237,651 from the Company's proposed amount of $20,610,694 to 20,373,043 (see Exhs. NG-RRP-2, Sch. 17, at 2 (Rev. 3); WP NG-RRP-6, Service Company Rents (Rev. 2); DPU 13-6).

b. Remaining Issues

As noted above, the Attorney General puts forth several recommendations with respect to the Company's IT planning and spending. First, the Attorney General recommends that the Company place a greater emphasis on end-of-life IT business applications (Attorney General Brief at 118, citing Exh. AG-BM-1, at 6-7). The record shows that National Grid's IT function has actively monitored and measured technical debt, and prioritizes infrastructure remediation according to security, operational, and financial

150 National Grid and NGSC qualify as affiliated companies under G.L. c. 164, § 85 and 220 CMR 12.02. D.P.U. 09-39, at 245-246.

risk (Exh. NG-ITP-Rebuttal-1, at 5-6). Further, since 2016, overall end-of-life unsupported infrastructure has been reduced from 76.5 percent to 37 percent in the U.S., and National Grid's IT function is committed to reducing this infrastructure to 15 percent over the next two years (Exh. NG-ITP-Rebuttal-1, at 5). The Department finds these efforts and results to be reasonable, and we expect the Company to continue to reduce end-of-life unsupported IT infrastructure as described. Based on these considerations and findings, we conclude that no Department action is necessary at this time.

Second, the Attorney General recommends the Company strive to defer discretionary IT projects whenever possible (Attorney General Brief at 118, citing Exh. AG-BM-1, at 7). The record shows that National Grid's IT investment plan relies on a balanced mix of discretionary and non-discretionary investments necessary to meet the Company's strategic and operational needs (Exh. NG-ITP-Rebuttal-1, at 7-10). The Department is not inclined to substitute its judgment for that of National Grid in determining how to structure its IT investment plan. The Company, however, must continue to provide sufficient operational and cost justification and documentation to support its IT investments. Thus, we conclude that no Department action is necessary at this time.

Third, the Attorney General recommends that the Company internalize and put into full effect the governance and controls described in the IT Operating Model Playbook and the IT Strategy and Strategic Business Plan as a means of maintaining capable, stable, supported, and secure IT systems (Attorney General Brief at 119, citing Exh. AG-BM-1, at 7). The IT Operating Model Playbook describes National Grid's IT principles, organization overview, and operating model (see generally Exh. NG-ITP-2). The IT Strategy and Strategic Business Plan is published annually to outline the strategic direction of the IT function, highlight any shifts in approach, and illustrate the impact of innovative technologies for National Grid (Exhs. NG-ITP-1, at 12; NG-ITP-3, at 3). We are satisfied that the Company is implementing its IT function consistent with the principles set forth in these documents and that there does not appear to be any misalignment between such principles and the Company's overall performance (Exhs. NG-ITP-1, at 12-13; NG-ITP-Rebuttal-1, at 13-14). We expect National Grid to update these manuals as necessary as it continues to regularly formulate and refine its IT strategy to meet its strategic and operational needs, and we direct National Grid to provide an appropriate narrative on this issue as part of the Company's next base distribution rate proceeding.

Fourth, the Attorney General recommends the Company continue to employ the KPI to ensure IT projects are completed on-time (Attorney General Brief at 119-120, citing Exh. AG-BM-1, at 11). Based on our review of the record, we are satisfied that the Company uses appropriate indices, including BEI, to track and report how closely a project is executing in comparison to the approved baseline plan (Exh. NG-ITP-Rebuttal-1, at 10-12). As such, we conclude that no Department action is necessary at this time.

Fifth, the Attorney General recommends that the Company continue its efforts to improve the quantification of benefits associated with IT investments, improve the benefits definition in its discretionary investment business case, and establish a more robust process to track benefits going forward (Attorney General Brief at 120-121, citing

Exh. NG-ITP-Rebuttal-1, at 12-14). The Department is satisfied that National Grid is addressing the Attorney General's concerns. In particular, National Grid's IT function implemented a benefit case process in 2020, which includes the creation of business cases for discretionary programs/investments that includes quantification of monetary benefits and cost avoidance (Exhs. NG-ITP-Rebuttal-1, at 14; AG 14-5). Further, National Grid's IT function is in the process of implementing a more formal benefit tracking process for benefits that continue to accrue after an IT project has closed (Exhs. NG-ITP-Rebuttal-1, at 14; AG 14-5). Based on these considerations, we conclude that no Department action is necessary at this time. The Department, however, directs National Grid to provide an update on these efforts as part of the Company's next base distribution rate proceeding.

Finally, the Department has reviewed the information provided concerning the replacement of the Company's current CIS program and the implementation of the SAP S/4 HANA program (Exhs. NG-ITP-1, at 26-39; NG-ITP-8 through NG-ITP-10; AG 38-7 through AG 38-13 & Atts.). The Department appreciates the Company's efforts in providing this information. As noted above, the Company states that there are implications associated with project implementation that will need to be considered in conjunction with the proposed PBR plan (Exh. NG-ITP-1, at 7). The Company's PBR plan is addressed in Section IV above. Further, National Grid is not requesting cost recovery in this proceeding for these projects (Exh. NG-ITP-1, at 7). As such, we need not address these projects in any further detail in this section.

F. Insurance Expense

1. Introduction

National Grid Insurance USA LLC ("NGI USA") and National Grid Insurance Company are captive insurance companies that provide insurance coverage to National Grid and its subsidiaries (Exh. NG-RRP-1, at 51). Insurance policies acquired on behalf of the Company from the captive insurance companies include public (excess) liability, business interruption, property, property terrorism, and cyber (Exh. NG-RRP-1, at 51). NGSC also procures other types of insurance coverage, including directors and officers ("D&O") liability insurance coverage, from direct insurance marketplace offerings on behalf of the Company (Exh. NG-RRP-2, Sch. 20, at 6 (Rev. 3)).

During the test year, National Grid booked insurance expenses of $2,238,800 (Exhs. NG-RRP-1, at 51; NG-RRP-2, Sch. 20, at 1 (Rev. 3)). National Grid then proposed a normalizing adjustment of $316,793 consisting of: (1) $26,667 for reclassifying insurance-related costs to insurance premium expense (i.e., consultants expense and other expense) that were recorded to Other O&M accounts during the test year; and (2) $290,126 representing the average experience credit received from one of the Company's insurers over the last five years (Exhs. NG-RRP-1, at 51; NG-RRP-2, Schs. 20, at 1, 3-4, 30, at 5 (Rev. 3)). National Grid also proposed known and measurable adjustments of $473,231 to reflect a comparison of the most recent insurance premium bills, and allocations to the Company, with the test-year level of insurance expense (Exhs. NG-RRP-1, at 51; NG-RRP-2, Sch. 20, at 2-3, 6 (Rev. 3)). Accounting for these adjustments results in a proposed pro forma expense for insurance premiums of $3,028,823 (Exh. NG-RRP-2, Sch. 20, at 2 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General takes issue with the Company's D&O liability insurance coverage expense (Attorney General Brief at 127-128). The Attorney General argues that the cost of this policy should not be fully borne by the ratepayers because the Company has failed to demonstrate that the primary purpose of the Company's D&O liability insurance policy is not to protect directors and officers from bad faith actions and has failed to show that the policy provides any measurable ratepayer benefits (Attorney General Brief at 127-128, citing D.P.U. 87-260, at 72; Western Massachusetts Electric Company, D.P.U. 86-280-A, at 95 (1987)).[151] In particular, the Attorney General questions whether ratepayers benefit when directors and officers are protected from the consequences of their own actions and why ratepayers should be responsible for protecting the directors and officers from their own wrongful acts (Attorney General Brief at 130). The Attorney General contends that while the Department has allowed companies to recover D&O liability insurance expense in prior dockets, those prior Orders did not directly address the issues she

151 The Attorney General notes that other business expenses that do not benefit ratepayers, such as lobbying costs and image-building campaigns, are disallowed for cost recovery (Attorney General Brief at 128, citing D.P.U. 91-106/91-138, at 60; D.P.U. 90-121, at 131; D.P.U. 88-170, at 29-30; New England Telephone and Telegraph Company, D.P.U. 86-33-G, at 101 (1989); New England Telephone and Telegraph Company, D.P.U. 411, at 19-20 (1981)).

raises in the instant matter (Attorney General Brief at 129, citing D.P.U. 17-170; D.P.U. 18-150).

The Attorney General, however, recognizes that the D&O liability insurance policies may assist the Company in attracting higher-quality personnel, and despite her claim that the Company has failed to meet its burden, she recommends that shareholders and ratepayers share the cost of these insurance expenses (Attorney General Brief at 129). Specifically, the Attorney General recommends that shareholders bear 75 percent of the allocated costs, while ratepayers bear 25 percent of the costs (Attorney General Brief at 129). In support of this recommendation, the Attorney General notes that the Connecticut Public Utilities Regulatory Authority routinely allows D&O liability insurance expenses to be shared 75/25 between shareholders and ratepayers, respectively, and that other states limit the recovery of such expenses (Attorney General Brief at 129-130 & n.113, citing United Illuminating Company, CT PURA Docket No. 16-06-04, at 36 (2016); Ni Florida, LLC, FL PSC Docket No. 160030-WS, Order No. PSC-16-0525-PAA-WS, at 8 (2016); Connecticut Natural Gas Corporation, CT PURA Docket No.13-06-08, at 27 (2014); Entergy Arkansas, Inc., Arkansas PSC Docket No. 06-101-U, Order No. 10, at 70, (2007); Centerpoint Energy Resources Corp., Arkansas PSC Docket No. 04-121-U, Order No. 16, at 40 (2005); Southwest Gas Corporation, CPUC Application 02-02-012, Decision 04-03-034, at 34–35 (2004)).

b. Company

National Grid argues that it has provided all relevant documentation to demonstrate that premiums charged by its captive insurers are competitive to what is available in the marketplace, and that the coverage available from the captive insurers is broader than competitive market alternatives, where applicable (Company Brief at 124-125, citing Exhs. NG-RRP-1, at 53; WP NG-RRP-7). Regarding the Attorney General's arguments, National Grid contends that D&O liability insurance is an ordinary business expense, and the primary purpose of the coverage is to protect the Company and ratepayers against a wide range of actual or alleged wrongful acts that do not include acts of bad faith (Company Brief at 190-191, citing Exhs. NG-RRP-Rebuttal-1, at 20-21; DPU 52-1). Thus, National Grid asserts D&O liability insurance coverage benefits customers by providing protection for the Company and ratepayers against potential liabilities that could result from alleged or wrongful acts of the Company's directors and officers (Company Brief at 191). Further, National Grid posits that maintaining D&O liability insurance coverage allows the Company to attract and retain higher quality directors and officers, which also benefits customers (Company Brief at 191). In addition, National Grid asserts that D&O liability insurance coverage allows the Company's directors and officers to better serve customers by diminishing the risk that those directors and officers will be personally financially harmed for any actions taken while carrying out their duties (Company Brief at 191). Finally, the Company states that the Department has allowed the inclusion of D&O liability insurance expense in the cost of service in prior dockets and, therefore, the full costs should be included in this proceeding as well (Company Brief at 191, citing D.P.U. 17-170, Exh. NG-DSD-2-BOS (C), Sch. 20, at 5; D.P.U. 18-150, Exh. NG-RRP-2 (C), Sch. 20, at 4).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expense based on a historic test year adjusted for known and measurable changes. D.P.U. 10-55, at 274; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. The Department will include the most current cost of liability and property insurance, based on a signed agreement, as a reasonable cost of service. D.P.U. 10-55, at 276; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; D.P.U. 86-86, at 8-10; Colonial Gas Company, D.P.U. 84-94, at 44 (1984). The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. D.P.U. 08-35, at 119-120; D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185.

The Attorney General contends that the Company failed to offer sufficient evidence regarding the primary purpose of its D&O liability insurance policy and any direct benefits to customers (Attorney General Brief at 127-128, 130). In evaluating the Company's D&O liability insurance coverage, the Department considers whether the primary purpose of the policy is to cover bad-faith actions and whether ratepayers receive measurable benefits. D.P.U. 87-260, at 72-73; Commonwealth Gas Company, D.P.U. 87-122, at 51, 53-54 (1987); D.P.U. 87-59, at 41-42. In determining ratepayer benefits, the Department considers whether ratepayers would otherwise be required to pay for damages and legal fees arising out of such suits brought against the Company's directors and officers in the event the Company did not have such insurance. D.P.U. 87-260, at 73.

The record in this case demonstrates that the purpose of the Company's D&O liability insurance policy[152] is to cover a wide range of possible allegations, including "neglect, errors, misstatements, misleading statements or omissions actually or allegedly caused, committed or attempted by or claimed against one or more" director or officer (Exh. DPU 51-1, Att. 1, at 3, 12-13). It also covers legal fees associated with defending the directors and officers (Exh. DPU 51-1, Att. 1, at 4, 7). The record does not support a finding that the primary purpose of the D&O liability insurance policy is to protect the directors and officers against bad faith actions. In fact, such actions appear to be expressly excluded by the policy (Exh. DPU 52-1, Att. 1, at 13).[153] Thus, we conclude that coverage by the policy primarily involves actions where the costs could be included in the Company's cost of service absent D&O liability insurance and, as such, the policy offers ratepayer benefits. As such, we find that the costs associated with the Company's D&O liability

---

152 The Company provided a copy of its primary D&O liability insurance policy issued by AEGIS and eight additional policies of excess coverage provided by other insurers (Exh. DPU 52-1 & Atts.). The terms of coverage and exclusions are set forth in the primary insurance policy.

153 For instance, the policy excludes claims arising out of or attributable to a director or office "having committed a deliberately fraudulent, dishonest, or malicious act or omission, or any knowing and intentional violation of any statute or regulation ..." (Exh. DPU 52-1, Att. 1, at 13).

insurance coverage are properly included in rates. D.P.U. 87-260, at 73; D.P.U. 87-122, at 53-54; D.P.U. 87-59, at 41-42.

The Department has reviewed National Grid's remaining insurance-related proposals, insurance policies, and supporting documentation, and we find that the Company's insurance expense premiums are based on actual policy rates and are thus known and measurable (Exhs. NG-RRP-1, at 50-53; NG-RRP-2, Sch. 20 (Rev. 3); WP NG-RRP-7; DPU 1-2; DPU 47-1 through DPU 47-6 & Supps; DPU 52-1 & Atts.; DPU 52-3; DPU 56-3; AG 1-61; AG 1-63; AG 13-7; AG 51-11 through AG 51-16 & Supps.). Further, the Department finds that National Grid has provided sufficient support to justify the use of captive insurance companies for some of the Company's insurance coverage, and that the Company has taken reasonable measures to control its insurance expense (Exhs. NG-RRP-1, at 51-53; WP NG-RRP-7; DPU 1-3 & Att.; AG 1-61 & Atts.; AG 51-12 (Supp.) & Atts.). Finally, the Department finds that the Company has correctly calculated its adjustments to insurance expense (Exhs. NG-RRP-1, at 50-53; NG-RRP-2, Sch. 20 (Rev. 3)). For all the reasons set forth above, the Department allows the Company's proposed pro forma expense for insurance premiums of $3,028,823.

G. Uninsured Claims Expense

1. Introduction

During the test year, National Grid booked uninsured claims expenses of $3,161,466 (Exhs. NG-RRP-1, at 50; NG-RRP-2, Sch. 19, at 1 (Rev. 3)). The Company then proposed a net normalizing adjustment of $238,342 consisting of: (1) a $3,315 reduction for Grade 3 significant environmental leak repair costs; and (2) a $241,657 increase based on a five-year average of actual amounts paid for general and automobile and worker's compensation claims in fiscal years 2016 through 2020 (Exhs. NG-RRP-1, at 50; NG-RRP-2, Sch. 19, at 1, 3-4 (Rev. 3)). Accounting for these adjustments results in a proposed pro forma expense for uninsured claims of $3,399,808 (Exh. NG-RRP-2, Sch. 19, at 2 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's use of a five-year average of uninsured claims is not representative of future recurring expenses (Attorney General Brief at 126). In particular, the Attorney General contends that the fiscal year 2019 claims expense is abnormally high due to two significant payments for personal injuries (Attorney General Brief at 126, citing Exhs. AG-JD-1, at 3; DPU 1-2; DPU 52-2). Thus, the Attorney General asserts that including the fiscal year 2019 claims expense improperly inflates the five-year average (Attorney General Brief at 127). As a result, the Attorney General argues that the Department should remove the fiscal year 2019 claims expense and instead calculate the Company's uninsured claims expense using a four-year average of fiscal years 2016, 2017, 2018, and 2020 (Attorney General Brief at 127).

b. Company

The Company argues that its use of a five-year average of actual claims paid to calculate its uninsured claims expense is consistent with Department practice (Company Brief at 188, citing D.P.U. 10-55, at 272). The Company contends that the purpose of using a five-year average of actual claims paid is specifically to account for the effect of "outlier" years, such as fiscal year 2019 (Company Brief at 188, citing Exh. NG-RRP-Rebuttal-1, at 18). Further, the Company argues that fiscal year 2019 is not anomalous because in the Company's prior base rate proceeding, it experienced total claims in 2012, which was one of the years used in the five-year average of actual claims paid, that were higher than the 2019 claims amount in the instant case (Company Brief at 188-189, citing Exh. DPU 52-2, Att. 2); see also D.P.U. 17-170, at 148. For these reasons, the Company asserts that the Department should allow the Company's proposed uninsured claims expense (Company Brief at 189).

3. Analysis and Findings

The Department recognizes that because self-insured damage claims vary from year to year, limiting recovery to test-year levels may not produce a representative level of claims expense on a forward-looking basis. D.P.U. 10-55, at 276; D.P.U. 09-30, at 219; see generally D.P.U. 87-59, at 35-40. The critical inquiry in examining uninsured claims expense is not whether the test-year amount is extraordinary but whether it is representative. D.P.U. 10-55, at 272. For this reason, the Department has used a five-year average to determine the level of self-insured payments for ratemaking purposes. D.P.U. 13-90, at 106; D.P.U. 10-55, at 272; D.P.U. 09-30, at 219-220; D.P.U. 89-194/195, at 73-75.

The Attorney General takes issue with including fiscal year 2019 in the Company's average of claims paid because of the disparate impact of two personal injury claims paid in that year (Attorney General Brief at 126, citing Exhs. AG-JD-1, at 3; DPU 1-2; DPU 52-2). As such, she asserts that the Department should remove all of the fiscal year 2019 claims from the calculation of the Company's self-insured expense and base the expense on a four-year average (Attorney General Brief at 127). We disagree.

National Grid has a self-insured retention policy under which the Company pays the first $3,000,000 of costs per occurrence (e.g., automobile accident, fire); this may result in multiple claims, but the claims relate to a single occurrence (Exh. DPU 52-3). The record shows that all monetary settlements paid in fiscal year 2019 for general and automobile claims were within the $3,000,000 deductible and, therefore, the Company and not its insurer paid these claims (Exhs. DPU 1-2, Att. 2; DPU 52-3). These include the specific claims referenced by the Attorney General, both of which were paid for personal injuries (Exhs. DPU 1-2, Att. 2; DPU 52-3). The Department finds that there is nothing in the record to suggest that the fiscal year 2019 claims, and particularly the two claims challenged by the Attorney General, are not representative of the types of events that would be covered under a typical general liability and automobile insurance policy. D.P.U. 10-55, at 273. Further, as noted, the amount of each claim was well below the Company's deductible, and there is no evidence that Company failed to act prudently in paying the two claims. Moreover, we find that the use of a five-year average in determining uninsured claims expense is to account for a year in which total claims were higher or lower than other years. For all of these reasons, we are not persuaded by the Attorney General's argument to exclude an entire year of claims because two of the claims in that year were uncommonly high. Accordingly, we will not exclude the fiscal year 2019 claims from the five-year average used to determine the appropriate level of self-insured payments for ratemaking purposes.

We find that National Grid has correctly calculated the proposed adjustment to the Company's self-insured expenses (Exhs. NG-RRP-1, at 50; NG-RRP-2, Sch. 19, at 1, 3-4 (Rev. 3)). Accordingly, the Department accepts National Grid's proposed uninsured expense adjustments.

H. Lease Expense

1. Introduction

During the test year, the Company booked $8,695,157 in lease expense associated with facilities in Amesbury, Dorchester, Waltham, West Roxbury, Wilmington, Quincy, Newton, Hyde Park, and Peabody, Massachusetts; Brooklyn, New York; and Washington, D.C. (Exhs. AG 7-3, Att. (Supp.); AG 32-6, Att. 1). The Company proposed the following adjustments to its test-year lease expense: (1) a decrease of $17,278 resulting from various normalizing adjustments; and (2) an increase of $1,415,820 increase for known and measurable changes to a number of the Company's leases (Exhs. AG 7-3, Att. (Supp.); AG 32-6 & Att. 1). Incorporating these adjustments results in a proposed pro forma lease expense of $10,093,699 (Exhs. NG-RRP-2, Sch. 30, at 4 (Rev. 3); AG 7-3, Att. (Supp.); AG 32-6 & Att. 1).

In particular, the Company's lease expense includes allocated charges related to two facilities located in Brooklyn, New York (Exhs. AG 32-3; AG 32-6, at 2-3 & Att. 1). The first site is the MetroTech Center, and the Company states the lease on this facility will expire in 2025 (Exhs. AG 2-18; AG 32-3). The second site is 2 Hanson Place, which the Company states was acquired in January 2020 to assume the MetroTech Center's operational responsibilities (Exhs. AG 32-2, Att. 2; AG 32-3). The Company proposed to include in its cost of service a rate year lease expense of $1,418,501 for the MetroTech Center facility, and a rate year lease expense of $463,673 for the 2 Hanson Place site (Exh. AG 32-6, at 2-3 & Att. 1).

2. Positions of the Parties

a. Attorney General

The Attorney General maintains that the Company's inclusion of both the MetroTech Center and 2 Hanson Place facilities in its cost of service is duplicative and should be disallowed (Attorney General Reply Brief at 61). Specifically, the Attorney General argues that the cost of the MetroTech Center facility is beyond what is reasonable and necessary to house the Company's operations (Attorney General Brief at 115). In this regard, the Attorney General notes that the MetroTech Center facility is approximately three times the area of the 2 Hanson Place space, and the cost of the MetroTech Center space allocated to the Company is approximately five times cost of the 2 Hanson Place facility (Attorney General Brief at 115, citing Exhs. AG 7-3, Att. (Supp.); AG 32-3; AG 32-6, Att. 1). The Attorney General also contends that to the extent the Company claims that the 2 Hanson Place site is appropriately sized, then this suggests that the size and cost of the MetroTech Center site are excessive (Attorney General Brief at 115). Further, the Attorney General notes that the Company's aggressive marketing of the MetroTech Center space for sub-lease is evidence that the facility is larger than necessary (Attorney General Brief at 115, citing Exh. NG-RRP-Rebuttal-1, at 10; RR-DPU-25).

The Attorney General also argues that the Company will double recover the cost of the MetroTech Center space through both base rates and from a sub-lessee, if it is able to successfully sublet the facility (Attorney General Brief at 115). Moreover, the Attorney General claims that the Company made no adjustments to the cost of the MetroTech Center lease to account for the relocation of a majority of employees who will relocate to the 2 Hanson Place facility, apart from a $35,000 reduction of the MetroTech Center facility's operating costs (Attorney General Reply Brief at 61-62, citing Exhs. AG 13-31; AG 29-2).

Based on these considerations, the Attorney General asserts that the entirety of the MetroTech Center facility allocated costs should be removed from the Company's proposed revenue requirement (Attorney General Reply Brief at 62). The Attorney General argues, however, that if the Department allows any amount of MetroTech Center lease expense to remain in the revenue requirement, then the amount should be limited to a pro rata reduction of the cost based on a square footage per employee remaining in the facility (Attorney General Reply Brief at 62). The Attorney General asserts that the Company should not include the full costs of both leases when one facility will only be partially occupied (Attorney General Reply Brief at 62).

b. Company

The Company disagrees with the Attorney General that the cost of the MetroTech Center facility should be removed from its cost of service (Company Brief at 186; Company Reply Brief at 37). The Company argues the timing was optimal to secure a lower cost lease at 2 Hanson Place due to favorable real estate market conditions in terms of variety and supply (Company Brief at 185, citing Exhs. NG-RRP-Rebuttal-1, at 10; AG 32-3). Further, the Company maintains that the 2 Hanson Place facility will result in lower rent and operating costs and, therefore, will provide benefits to employees and ratepayers (Company Brief at 185).

Further, the Company notes that it intends to begin the process of moving the MetroTech Center employees to the 2 Hanson Place office by August 1, 2021, although this date is dependent on the evolving situation with the COVID-19 pandemic (Company Brief at 185-186; Company Reply Brief at 39). The Company maintains that the moving process will take time, so it has decreased the operating expense attributed to the MetroTech Center facility by approximately $35,000 to compensate for its plans to relocate employees (Company Brief at 186). Ultimately, the Company argues that it has properly accounted for the phased process of transferring employees to the 2 Hanson Place facility while simultaneously decommissioning the MetroTech Center facility (Company Brief at 186).

The Company also disagrees with the Attorney General's argument that recovery for the MetroTech Center facility should be based on a pro rata reduction based on the square footage per employee remaining in the MetroTech Center facility (Company Reply Brief at 39). The Company states that this is a speculative approach as the anticipated move-in date for the 2 Hanson Place office is subject to National Grid's COVID-19 re-entry plan at the time (Company Brief at 185; Company Reply Brief at 39). The Company maintains that there is no evidence that the MetroTech Center space is not currently fully occupied and used and useful (Company Reply Brief at 39).

Finally, the Company argues that lease arrangements related to the MetroTech Center and 2 Hanson Place facilities have been reasonable and prudently managed (Company Reply Brief at 38). National Grid asserts that the MetroTech Center facility is still required for operational support and that it is unlikely that a sub-lessee will be found in the foreseeable future due to the impact of the COVID-19 pandemic on the sub-lease market (Company Brief at 186; Company Reply Brief at 38). Based on these considerations, the Company maintains that the full costs of both leases should be included in the proposed revenue requirement (Company Reply Brief at 38).

3. Analysis and Findings

a. Introduction

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

The Department permits rate recovery of payments to affiliates where those payments are: (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and

(3) allocated to the utility by a formula that is both cost effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates.

D.P.U. 95-118, at 41, citing D.P.U. 92-101, at 42-46; D.P.U. 85-137, at 51-52. In addition, 220 CMR 12.04(3) provides that: "An Affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided."

b. Brooklyn, NY Leases

As noted above, the Attorney General objects to the inclusion in National Grid's proposed cost of service of $1,418,501 in lease expense allocated to the Company for the MetroTech Center facility (Attorney General Brief at 115-116; Attorney General Reply Brief at 61-62). In particular, the Attorney General raises concern about the possibility of double recovery if the costs for both the MetroTech Center lease and the 2 Hanson Place lease are included in National Grid's revenue requirement, given the commitment to sub-leasing the former facility (Attorney General Brief at 115-116; Attorney General Reply Brief at 62).

When lease expenses are based on a new or renovated facility, part of the Department's decision on whether the lease expenses are reasonable has been based on whether the underlying facility is in use. D.P.U. 19-120, at 265-266 (allowing lease upon substantial evidence that facility was in use and providing benefits to ratepayers); D.P.U. 13-75, at 210 (allowing lease expenses associated with new facilities based on the lease's occupancy date); D.P.U. 09-39 (disallowing lease expenses associated with facility renovations that would not have been completed for six months).

The record shows that NGSC currently has employees based at MetroTech Center in Brooklyn who provide services, such as human resources, finance, and procurement, to National Grid USA's affiliates (Exh. AG 2-18). The facility is approximately 254,000 square feet of office space and houses 846 full-time employees (Exhs. AG 2-18; AG 13-31, at 2; AG 32-3). The existing lease is due to expire in February 2025 (Exhs. AG 2-18; AG 32-3).

On January 14, 2020, NGSC entered a written lease for the eleventh and twelfth floors of 2 Hanson Place, also located in Brooklyn (Exh. AG 32-2, Att. 2, at 5, 80). This facility is approximately 86,000 square feet (Exhs. AG 2-18; AG 32-3). The record shows that NGSC plans to relocate 675 of the employees from the MetroTech Center facility to 2 Hanson Place, and to retain the call center, customer office and sustainability hub employees at the MetroTech Center until the end of that site's lease term (Exhs. AG 2-18; AG 13-31, at 2).

The portion of the MetroTech Center facility that no longer would be used by NGSC was marketed for sub-lease beginning in December of 2019 (RR-DPU-25). National Grid explained, however, that the COVID-19 pandemic adversely affected the sublet market in New York and, as such, the Company does not expect to sublet any portion of the MetroTech Center for the foreseeable future (Exhs. NG-RRP-Rebuttal-1, at 10; AG 13-32).

By the end of February 2021, no employees had been relocated to 2 Hanson Place (Exh. AG 13-31, at 2). National Grid stated that the 2 Hanson Place facility was substantially completed on April 30, 2021, though the Company provided no documentation to substantiate this representation. Further, the Company stated that it was anticipated that employees would move into the 2 Hanson Place facility by August 1, 2021, "depending on National Grid's COVID-19 re-entry plan at that time" (RR-DPU-26). There is no evidence on the record detailing the Company's "re-entry plan." Additionally, National Grid conceded that it had not yet experienced cost savings or avoided costs related to the relocation of the Brooklyn facilities and does not expect to achieve such savings or avoided costs during the rate year (Exh. AG 13-31).

Based on these considerations, the Department finds that the Company has failed to demonstrate that the 2 Hanson Place facility is currently in use and providing benefits to Massachusetts ratepayers.[154] Further, we find that National Grid's representation that the relocation would occur on August 1, 2021, subject to the Company's "COVID-19 re-entry plan," is insufficient to establish that such relocation did, in fact, occur, or will occur by a specific date. Therefore, the Department disallows recovery of costs associated with the 2 Hanson Place facility. Accordingly, the Department will reduce the Company's proposed cost of service by $463,673.

---

154 Moreover, it is unclear whether any rent is currently being paid for the 2 Hanson Place space. According to the lease, the rent commencement date shall be 14 months following the earlier of "(i) the date on which Landlord tenders delivery of vacant possession of the Premises to Tenant in broom clean condition with Landlord's Work Substantially Completed ... and (ii) the date Tenant or anyone claiming by, under or through Tenant first takes possession of all or any portion of the Premises for any purpose" (Exh. AG 32-2, Att. 2, at 5).

With respect to MetroTech Center, the Department finds that the Company's proposed lease expense is reasonable and known and measurable. At the close of the record in this case, the facility was in use and providing benefits to Massachusetts ratepayers (Exh. AG 13-31). Further, given the uncertainty surrounding the relocation to 2 Hanson Place, any further adjustment to the MetroTech Center lease expense would be speculative. Accordingly, the Department allows the Company's proposed rate year level of expense for this facility.

c. Remaining Leases

The Department has reviewed the record regarding the Company's remaining leases and proposed adjustments (Exhs. NG-RRP-Rebuttal-1, at 8-10; AG 7-3, Att. (Supp.); AG 32-2 & Att. 1; AG 32-3; AG 32-4 & Att.; AG 32-5; AG 32-6 & Atts.; AG 32-7; AG 32-8; AG 52-1 & Att.; AG 52-2; Tr. 4, at 540). We find that the Company's leases are reasonable, and that the proposed adjustments are known and measurable, with one exception. The Company proposed to include in its cost of service a rate year lease expense of $350,000 related to a new lease for a facility located on Webster Avenue in Newton, Massachusetts (Exhs. NG-RRP-Rebuttal-1, at 8-10, 11 n.13; AG 32-6, Att. 1). The Company noted, however, that it would remove this expense if the signed lease was not provided prior to the close of the record (Exh. NG-RRP-Rebuttal-1, at 11 n.13; Tr. 4, at 539-540). The Company acknowledged in its reply brief that it did not obtain an executed Webster Avenue lease by the close of the record in this proceeding, and that it would remove the amount of the lease from its cost of service in this proceeding (Company Reply Brief at 36-37). Despite this representation, the Company did not remove the costs associated with the Webster Avenue lease from its proposed cost of service (see Exhs. NG-RRP-2, Sch. 30, at 4 (Rev. 3); NG-RRP-5, at 3 (Rev. 3); AG 7-3, Att. (Supp.); AG 32-6, Att. 1). Accordingly, the Department will reduce the Company's proposed cost of service by an additional $350,000.

d. Conclusion

Based on the foregoing, the Department has reduced the Company's proposed cost of service by $813,673. Accordingly, the Company's rate year level of facilities lease expense shall be $9,280,026.

I. Property Tax Expense

1. Introduction

In D.P.U. 17-170, the Department approved National Grid's request to determine its property tax expense based on the valuation method used by the specific municipality in the Company's service area. D.P.U. 17-170, at 168, 174-175. National Grid states that consistent with this approval, for municipalities that use the net book value ("NBV") valuation method for personal property, the Company uses the most recent Form of Lists ("FOLs"), as well as the most recent tax bills, to determine property tax expense, based on the first quarter 2021 FOLs (Exh. NG-PML-1, at 9). For municipalities that use a hybrid NBV and reproduction cost new less depreciation ("RCNLD")[155] method ("Hybrid

[155] The RCNLD valuation method applies a cost-inflationary factor to age the property in question, with a 20-percent floor on the value of the asset. D.P.U. 17-170, at 169

RCNLD/NBV"),[156] the Company uses the latest property tax bills received by those municipalities during this proceeding, adjusted for the change in personal property tax valuations between December 31, 2019 and December 31, 2020 when the 2021 FOLs became available in the first quarter of 2021 (Exhs. NG-PML-1, at 9-10; WP NG-RRP-9m (Rev. 2); WP NG-RRP-9n (Rev. 2)).

At the time of initial filing in the instant proceeding, the Company indicated that eleven of the 131 municipalities in its service territory had transitioned to the Hybrid RCNLD/NBV method, which resulted in incremental property tax expenses of $7,973,229 annually (Exhs. NG-PML-1, at 14; WP NG-RRP-9j (Rev. 2); RR-AG-9).

During the test year, National Grid booked $67,152,579 in property tax expense (Exh. NG-RRP-2, Sch. 7, at 1 (Rev. 3)). In its filing, National Grid applied a normalizing adjustment of negative $7,700 to remove an incorrect Boston Gas tax bill from the test year, and for property tax expense that NGSC reclassified in the test year (Exhs. NG-RRP-1, at 80; NG-RRP-2, Sch. 7, at 1, 3 (Rev. 3)). The Company then proposed an increase of $18,996,653 to reflect the rate year revenue requirement based on the most recent FOLs and associated property tax information (Exh. NG-RRP-2, Sch. 7, at 2 (Rev. 3)). Accounting for

n.90, citing Boston Gas Company v. The Board of Assessors of Boston, Docket Nos. F275055, F275056, at Appellate Tax Board 2009-1232 (December 16, 2009).

156 The Hybrid RCNLD/NBV method involves assessments based on 50 percent of a property's NBV and 50 percent of the RCNLD value (Exh. NG-PML-1, at 12).

these adjustments results in a proposed pro forma property tax expense of $86,141,532 (Exh. NG-RRP-2, Sch. 7, at 2 (Rev. 3)).

The Company's property tax expense includes amounts associated with construction work in progress ("CWIP") (Exh. NG-RRP-2, Sch. 7, at 4-7 (Rev. 3)). For municipalities using the NBV method of assessing property taxes, CWIP personal property was valued at $45,728,904 (Exh. NG-RRP-2, Sch. 7, at 4-6 (Rev. 3)). For municipalities using the hybrid RCNLD/NBV method, CWIP personal property was valued at $159,384,047 (Exhs. NG-RRP-2, Sch. 7, at 7 (Rev. 3); WP NG-RRP-9m (Rev. 2); WP NG-RRP-9n (Rev. 2)). Therefore, the total value of the Company's CWIP personal property was $205,112,951. The total CWIP-related property taxes are $4,393,449 based on each municipality's CWIP personal property multiplied by each respective municipality's mill rate (see Exhs. WP NG-RRP-9g (Rev. 2); WP NG-RRP-9k (Rev. 3); WP NG-RRP-9l (Rev. 2); WP NG-RRP-9m (Rev. 2); WP NG-RRP-9n (Rev. 2)).[157]

2. Positions of the Parties

a. Attorney General

The Attorney General argues that National Grid should not recover property tax amounts above the NBV value of the Company's assets from ratepayers because any valuation above NBV only benefits shareholders and not customers (Attorney General Brief

[157] More specifically, this amount was derived based on the aggregate sum of each municipality's mill rate as a percent multiplied by each respective municipality's CWIP personal property amount stated on their FOL (Exhs. NG-RRP-2, Sch. 7, at 4-7 (Rev. 3); WP NG-RRP-9g (Rev. 2)).

at 134). In particular, the Attorney General reasons that a sale of these assets at the increased valuation benefits shareholders, and, therefore, ratepayers should not pay for the increased property taxes on these assets (Attorney General Brief at 134, 136; Attorney General Reply Brief at 65-66). The Attorney General also notes that the Department uses NBV for ratemaking purposes even when municipalities use the Hybrid RCNLD/NBV method for property tax purposes, based on the presumption that the NBV of utility assets is the proper value for assessment purposes, absent special circumstances that would induce a buyer to pay more than NBV (Attorney General Brief at 136, citing Boston Gas Company v. Board of Assessors, 458 Mass. 715, 718-719, 729 (2011).

Alternatively, the Attorney General argues that if the Department allows the recovery of property tax expense based on the Hybrid RCNLD/NBV method, ratepayers should receive the gains on any sale or divestiture transaction of a utility, and not only on the sale of any individual plant asset or group of assets, but also on the sale of the corporation or legal entity that holds those assets (Attorney General Brief at 137, citing D.P.U. 10-55, at 226-227; D.P.U. 08-35, at 138; D.P.U. 96-50 (Phase I) at 111; Barnstable Water Company, D.P.U. 93-233-B at 12-13 (1994); D.P.U. 88-135/151, at 91).

The Attorney General also argues that the Department should remove CWIP-related property taxes from the Company's property tax expense (Attorney General Brief at 138). She asserts that these costs should be capitalized rather than expensed based on the Department's accounting regulations, lack of Department precedent, and the record in this proceeding (Attorney General Brief at 138-139, citing 220 CMR 50.00; Exhs. DPU 25-3;

AG 20-16; Attorney General Reply Brief at 66-68). Further, the Attorney General contends that if the Company is allowed to recover CWIP-related property taxes, it will double-recover those taxes (Attorney General Brief at 139-140). According to the Attorney General, under the Company's proposal it would recover CWIP-related property taxes once as a property tax expense, and a second time after it capitalizes the property taxes during the construction period and includes those costs in plant in service (Attorney General Brief at 139). Finally, the Attorney General argues that if the Company seeks an exception to the Department's accounting rules, it should request a separate rulemaking to receive such treatment (Attorney General Reply Brief at 68).

b. Company

The Company asserts that it has appropriately followed Department precedent by incorporating information from its most recent tax bills and personal property values from the latest FOLs (Company Brief at 150, citing Exhs. NG-RRP-1, at 80; NG-PML-1, at 4; D.P.U. 17-170, at 174). The Company maintains that there is a substantial lag from the point where the calendar year ends and the associated NBV information is included on the property tax bills (Company Brief at 151, citing Exh. NG-PML-1, at 7). Therefore, the Company argues it appropriately relied on a method to establish a rate year property tax expense that incorporates up-to-date information and as such reflects a more reliable representation of the revenue requirement (Company Brief at 153-155, citing Exhs. NG-PML-1, at 9; WPs NG-RRP-9m (Rev. 1); WP NG-RRP-9n (Rev. 1)).

Regarding CWIP-related property taxes, the Company argues that capitalizing these amounts results in reporting a higher asset basis, effectively requiring the Company to pay property tax on capitalized property taxes (Company Brief at 70; Company Reply Brief at 54). The Company concedes that the Department's specific accounting regulation, 220 CMR 50.00, directs the taxes on physical property to be included in gas plant accounts "where applicable" (Company Brief at 70; Company Reply Brief at 53, citing RR-AG-11). The Company, however, avers that because capitalizing property taxes on CWIP would duplicate costs, it does not view property taxes on CWIP "as applicable" to the computation of CWIP for the purposes to which CWIP is used for municipal property taxes (Company Brief at 70; Company Reply Brief at 53-54). Thus, expensing property taxes on CWIP, the Company argues, is the correct approach because these costs are not recovered elsewhere (Company Brief at 71, citing Exh. NG-RRP-2, Sch. 7, at 4-6 (Rev. 1); Company Reply Brief at 54). Further, the Company claims that excluding the recovery of CWIP-related property taxes produces an understatement of expenses incurred in the rate year (Company Brief at 71; Company Reply Brief at 54). Finally, National Grid states the CWIP-related property taxes were allowed in Massachusetts Electric Company and Nantucket Electric Company's prior base distribution rate case, so there is no basis for the Attorney General's argument that this issue should be decided in a separate rulemaking (Company Reply Brief at 55 & n.9, citing D.P.U. 18-150, Exh. NG-RRP-1, at 88).

3. Analysis and Findings

a. Introduction

The Department's current policy to determine property tax expense is based on the Company's most recent FOL submission to the Massachusetts Department of Revenue ("DOR"), in conjunction with information contained in the most recent tax bills (Exh. NG-PML-1, at 9-10). See also D.P.U. 17-170, at 174. Because they are considered verifiable, non-controversial evidence, the Department holds the record open in a proceeding to receive from the utility the most current tax bills issued by cities and towns. D.P.U. 14-150, at 209; D.P.U. 88-67 (Phase I) at 165-166; D.P.U. 84-94, at 19.

b. Treatment of Incremental Taxes

As noted above, the Attorney General argues that National Grid should not recover property tax amounts above the NBV value of the Company's assets because any valuation above NBV only benefits shareholders and not customers (Attorney General Brief at 134-136; Attorney General Reply Brief at 65-66). The Department recognizes that a municipality's adoption of the Hybrid RCNLD/NBV method may increase property valuations, which, in turn, increases the Company's property taxes in that municipality (Exh. NG-PML-1, at 15). The higher valuations are then reflected in the Company's cost of service based on the FOL and property tax bill for that municipality (Exh. NG-PML-1, at 9-10). The adoption of an alternative to the NBV method of assessing property taxes rests with the municipality. The Department has acknowledged that, with the exception of applications for abatements, property taxes are largely outside of a company's control. D.P.U. 15-155, at 215. Further, while the increased property valuations resulting from adoption of the Hybrid RCNLD/NBV method may benefit the Company at the time of a hypothetical sale in the future, the Company does not realize any gain or benefit until the sale occurs. For these reasons, we find that the Company's known and measurable incurred property taxes above NBV should be eligible for cost recovery.

The Department, however, acknowledges the arguments made by the Attorney General regarding the treatment of gains on non-depreciable assets such as land (Attorney General Brief at 137). D.P.U. 10-55, at 226-227; D.P.U. 08-35, at 138; D.P.U. 96-50 (Phase I) at 111; D.P.U. 93-233-B at 12-13; D.P.U. 88-135/151, at 91. Our decision today does not modify the Department's precedent requiring the return to ratepayers of the entire gain associated with the sale of non-depreciable assets if those assets were recorded above-the-line and supported by ratepayers. See, e.g., D.P.U. 10-55, at 226-227; D.P.U. 08-35, at 138; D.P.U. 96-50 (Phase I) at 111; D.P.U. 93-233-B at 12-13; D.P.U. 88-135/151, at 91.

c. CWIP-related Property Taxes

Next, the Attorney General argues that the Department should remove CWIP-related property taxes from the Company's property tax expense and that these costs should be capitalized instead of expensed (Attorney General Brief at 138-139, citing 220 CMR 50.00; Exhs. DPU 25-3; AG 20-16; Attorney General Reply Brief at 66-68). The Department has previously excluded CWIP-related property taxes from a company's cost of service. D.P.U. 15-155, at 214; D.P.U. 94-50, at 373; D.P.U. 88-135/151, at 100; Western

Massachusetts Electric Company, D.P.U. 558, at 22-23 (1981).[158] The Department's relevant accounting regulation, 220 CMR 50.00, provides that "the cost of construction properly includible in gas plant accounts shall include, where applicable, the direct and overhead costs." Taxes are subsequently defined to "include taxes on physical property (including land) during the period of construction and other taxes properly includible in construction costs before the facilities become available for service." 220 CMR 50.00.

The regulation's use of the phrase "where applicable" is a classification of the types of costs that are to be included and excluded when calculating the cost of construction. Direct and overhead costs such as materials, workers' wages, and property taxes for utility operations related to the project are capitalized. 220 CMR 50.00. Indirect construction costs such as income taxes and property taxes on constructing a building for solely non-utility operations are not capitalized. We do not interpret the term "where applicable" as conferring discretion to the Company to choose to expense items that otherwise should be capitalized for ratemaking purposes. Therefore, the Department determines that CWIP-related property taxes should be capitalized.

---

158 National Grid asserts that the Department has previously allowed CWIP-related property taxes (Company Reply Brief at 55 & n.9, citing D.P.U. 18-150, Exh. NG-RRP-1, at 88). A general principle of administrative law is that an administrative body can only go against precedent where it adequately explicates the basis of its new interpretation. United Automobile Workers v. National Labor Relations Board, 802 F.2d 969, 974 (1986). The Department adequately explains its reasoning above.

Moreover, the Department is not persuaded by the Company's arguments that (1) capitalizing the CWIP-related property taxes results in a higher asset basis that requires the Company to pay property tax on capitalized property taxes, and (2) excluding the recovery of CWIP-related property taxes produces an understatement of expenses incurred in the rate year (Company Brief at 70-71; Company Reply Brief at 54). By failing to capitalize CWIP-related property taxes since D.P.U. 17-170, the Company has understated its gas plant accounts by the amount of CWIP-related property taxes expensed (Exh. AG 20-16). Based on the record before us, we find that following the Department's prescribed accounting procedures results in a return to the proper valuation of the Company's assets.

Finally, the Company contends that expensing CWIP-related property taxes is appropriate because the costs cannot be recovered elsewhere (Company Brief at 71). We disagree. Upon completion of the construction project, the accumulated CWIP-related property taxes are included in the capital amount and become eligible for depreciation over the service life of the respective asset. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; D.P.U. 84-135, at 23. Therefore, we find that the Company is able to recover the property tax, when appropriate, through its cost of service as a part of depreciation expense.

Based on the foregoing considerations and findings, the Department finds that the Company's property tax expense shall not include CWIP-related property taxes. Thus, the Department will reduce the Company's proposed cost of service by $4,393,449 to reflect the removal of CWIP-related property taxes.

d. Conclusion

The Department finds that, with the noted exception of including CWIP-related property taxes, the Company's method of calculating property tax expense for communities using the NBV valuation method and for communities using the Hybrid RCNLD/NBV method produces a non-speculative, reliable measure of the Companies' rate year tax expense, satisfies the Department's known and measurable standard, and is in line with Department precedent. D.P.U. 17-05, at 250-251; D.P.U. 12-86, at 243-245; D.P.U. 95-118, at 148. Further, we conclude that the Company has provided appropriate documentation to support its proposed level of property tax expense, minus the inclusion of CWIP-related property taxes (Exhs. NG-RRP-2, Sch. 7, at 4-7 (Rev. 3); WP NG-RRP-9k (Rev. 3); WP NG-RRP-9l (Rev. 2); WP NG-RRP-9m (Rev. 2); WP NG-RRP-9n (Rev. 2)). As noted above, the Department will reduce the Company's proposed cost of service by $4,393,449 to reflect the removal of CWIP-related property taxes. Accordingly, we approve an overall increase to the Company's adjusted test-year level of property tax expense of $14,603,204 ($18,996,653 - $4,393,449).

J. Non-Industry Dues and Memberships

1. Introduction

The Company maintains memberships in various non-industry trade associations and organizations (Exhs. NG-RRP-Rebuttal-1, at 22-23; AG 13-9 & Atts.). During the test year, National Grid booked $21,556 in non-industry dues and memberships allocated to the Company from NGSC (Exhs. NG-RRP-2, Sch. 30 (Rev. 3); AG 13-9).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company should not be allowed to recover the costs of its non-industry dues and memberships because it has not demonstrated a clear link between those costs and ratepayer benefits (Attorney General Brief at 131; Attorney General Reply Brief at 63). The Attorney General maintains that the dues and memberships in question are unnecessary for the Company's provision of natural gas service and instead contribute to building the Company's image and providing business networking services (Attorney General Brief at 131). The Attorney General further claims that two of the examples offered by the Company in support of its proposal, Edison Electric Institute ("EEI") and the Electric Power Research Institute ("EPRI"), are, in fact, industry associations, and, therefore, do not support the recovery of non-industry dues and memberships expense (Attorney General Reply Brief at 63). Based on these arguments, the Attorney General asserts that the Company has not adequately demonstrated how these costs benefit ratepayers, and the Company should be disallowed from recovering such costs (Attorney General Brief at 131; Attorney General Reply Brief at 63).

b. Company

The Company argues that its non-industry dues and membership costs help support its provision of natural gas service, so these organizations benefit ratepayers indirectly (Company Brief at 192; Company Reply Brief at 41). Although National Grid acknowledges that EEI and EPRI are "utility industry" organizations, the Company also notes that

Northeast Business Group on Health, the Institute for Energy and Sustainability, the Interstate Natural Gas Association of America, the Northeast Gas Association, and Our Nation's Energy Future Coalition are examples of non-industry organizations that do, in fact, indirectly provide benefits to ratepayers (Company Brief at 192-193; Company Reply Brief at 39-41). National Grid argues that its membership in these organizations allows it to obtain valuable information on topics as varied as health benefits administration and methane emissions reduction, all of which benefit ratepayers through cost savings and more effective pro-environment policies (Company Brief at 192-193; Company Reply Brief at 39-41). Therefore, the Company asserts that ratepayers benefit from the Company's continued membership in such organizations and the costs associated with these memberships should be recoverable (Company Brief at 193; Company Reply Brief at 41).

3. Analysis and Findings

The Department requires that the Company demonstrate a link between non-industry dues and memberships and ratepayer benefits for the costs to be recoverable in rates. See, e.g., D.P.U. 92-111, at 127; D.P.U. 92-101, at 54; D.P.U. 90-121, at 151. In support of its position that the costs should be recoverable, the Company lists vague benefits conferred by these non-industry memberships and details the activities of a select number of organizations (Exh. NG-RRP-Rebuttal-1, at 22-23; Company Reply Brief at 39-40). Further, while we recognize that some of these memberships may help National Grid stay informed of various developments and provide insight on issues relevant to the Company's business, we are not persuaded that these memberships are necessary to the provision of natural gas service to customers or that there is a clear link to customer benefits. As such, we find that it is inappropriate for the Company's ratepayers to fund these non-industry dues and memberships.

Based on the considerations and findings above, we deny the Company's proposal to recover non-industry dues and memberships from customers. Accordingly, the Department reduces the Company's proposed cost of service by $21,556. As a result of this decrease, inflation expense will be updated in Schedule 2A below.

K. Verizon Credit

1. Introduction

During the test year, the Company received a credit in the amount of $731,723 from Verizon in exchange for IT-related substation work performed between November 1, 2019 and March 31, 2020 (Exh. AG 52-3). Because National Grid considers the credit to be non-recurring in nature, the Company proposes a normalizing adjustment of $731,723 to reflect the removal of the credit from the proposed cost of service (Exhs. AG 37-1, Att. 3, at 2, 11; AG 52-3).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company's normalizing adjustment to remove the Verizon credit is not appropriate and should be rejected (Attorney General Brief at 124). The Attorney General contends that National Grid's proposed removal of the Verizon credit would result in the Company recovering expenses for which it was already compensated

(Attorney General Brief at 124-125). Further, the Attorney General argues that the Company has not adequately explained why it was compensated for the work and has not demonstrated that it would not be reimbursed again in the future (Attorney General Reply Brief at 73). Thus, the Attorney General asserts that National Grid's proposed adjustment would allow the Company to improperly recover expenses it did not incur in the test year and for which it may not incur in the future (Attorney General Reply Brief at 73-74).

b. Company

The Company argues that the Verizon credit was a one-time, non-recurring credit received for IT-related work and, therefore, it was appropriate to remove the credit from the test-year cost of service (Company Reply Brief at 45, citing Exhs. AG 37-1, Att. 3; AG 52-3). Therefore, National Grid asserts that the normalizing adjustment is necessary because without it the Company's cost of service would be understated in the rate year (Company Reply Brief at 45).

3. Analysis and Findings

The Department typically includes a test-year level of expenses in cost of service and will adjust this level only for known and measurable changes. D.P.U. 11-01/D.P.U. 11-02, at 345; D.P.U. 07-71, at 120; D.P.U. 87-260, at 75. In this regard, the Department consistently has held that there are three classes of expenses that are recoverable through base rates: (1) annually recurring expenses; (2) periodically recurring expenses; and

(3) extraordinary non-recurring expenses.[159] Milford Water Company, D.P.U. 17-107, at 104-105 (2018); Aquarion Water Company of Massachusetts, D.P.U. 17-90, at 165 (2018); D.P.U. 15-80/D.P.U. 15-81, at 130; D.P.U. 11-01/D.P.U. 11-02, at 345; D.T.E. 98-51, at 35; D.P.U. 95-118, at 121-122; D.P.U. 1270/1414, at 32-33.

The Department is satisfied that the Verizon credit was a one-time credit received for IT-related substation work performed during the test year (Exhs. AG 37-1, Att. 3, at 2, 11; AG 52-3). There is no convincing evidence to establish that the credit will recur in the future. Further, the Department finds that the credit is non-extraordinary in nature and amount.

Based on these considerations and findings, the Department concludes that removing the one-time Verizon credit is appropriate and results in a representative amount of expense for the rate year. Thus, no further adjustments are necessary. Accordingly, the Department accepts National Grid's normalizing adjustment of $731,723 to reflect the removal of the credit from the proposed cost of service.

L. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $3,135,361 in rate case expense (Exhs. NG-RRP-1, at 75; NG-RRP-2, Sch. 4, at 4). Based on its final invoices and

---

159 In instances where an expense is periodically recurring or non-recurring but extraordinary in nature, the amount may be amortized over an appropriate time period. D.P.U. 1270/1414, at 33; see also D.P.U. 89-114/90-331/91-80 (Phase One) at 152; Western Massachusetts Electric Company, D.P.U. 88-250, at 65-67 (1989).

projected costs to complete the compliance filing, the Company proposes a total rate case expense of $2,967,496 (Exh. NG-RRP-2, Sch. 33, at 4 (Rev. 3); see also Exh. DPU 12-16, Att. 9 (Supp. 3)). National Grid's proposed rate case expense includes costs related to legal representation and expert consulting services related to the Company's (1) revenue requirement, (2) PBR proposal, (3) compensation and benefit studies, (4) depreciation study, (5) proposed ROE and capital structure, and (6) rate case support (Exhs. NG-RRP-2, Sch. 33, at 4 (Rev. 3); DPU 12-16, Att. 9).

The Company proposes to normalize the rate case expense over a five-year period consistent with the term of its proposed PBR plan (Exhs. NG-RRP-1, at 75; NG-RRP-2, Sch. 33, at 4 (Rev. 3)). Normalizing the Company's proposed rate case expense of $2,967,496 over five years produces an annual expense of $593,499 (Exh. NG-RRP-1, Sch. 33, at 4 (Rev. 3)).

2. Positions of the Parties

The Company maintains that its rate case expense costs are reasonable and meet all requirements to warrant cost recovery (Company Brief at 147, 149). The Company contends that it endeavored to contain costs during the base distribution rate case by conducting a request for proposals ("RFP") process (Company Brief at 148, citing Exhs. DPU 12-1; DPU 12-2; DPU 12-6). National Grid asserts that because it has proposed a five-year PBR plan, the Department should permit the Company to normalize the costs over five years (Company Brief at 147, citing Exh. NG-RRP-1, at 75; D.P.U. 18-150, at 250-251). No intervenor addressed this issue on brief.

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that actually has been incurred and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 226-227; D.P.U. 95-118, at 115-119.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 220; D.P.U. 09-39, at 289-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; see also D.P.U. 93-223-B at 16-17.

b. Competitive Bidding Process

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-59; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with a competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

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

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

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

ii. <u>Company's RFP Process</u>

The Company seeks to include expenses associated with the following: (1) revenue requirement; (2) PBR proposal; (3) compensation and benefits studies; (4) depreciation study; (5) proposed ROE and capital structure; (6) rate case support; (7) rate design; (8) legal representation; and (9) interpretation services (Exhs. NG-RRP-2, Sch. 33, at 4 (Rev. 3); DPU 12-8; DPU 12-16, Att. 9 (Supp. 3)). National Grid provided documentation demonstrating that it conducted a competitive bidding process for each of its service providers, with the exception of the compensation survey provider (Exh. DPU 12-7).[160]

The Department has determined that if a company decides to forgo the competitive bidding process, there must be an adequate justification for the company's decision to do so. D.P.U. 14-150, at 219; D.T.E. 01-56, at 76. The service provider that conducted the compensation study is a recognized authority in the field and provides compensation studies to all investor-owned Massachusetts utilities, including the Company. See, e.g., D.P.U. 17-170, at 96; D.P.U. 17-05, at 132; D.P.U. 15-155, at 152-153; D.P.U. 15-80/D.P.U. 15-81, at 103, 108-109; D.P.U. 13-75, at 144-145. The Department finds that, in this instance, conducting a separate RFP for the sake of process, rather than to establish a field of potential bidders and establish price and non-price qualifications would have been inefficient. D.P.U. 13-75, at 237; Bay State Gas Company, D.P.U. 12-25, at 192 (2012); D.P.U. 10-114, at 231; D.P.U. 09-30, at 232. Thus, we find that there is sufficient justification for the Company forgoing the competitive bidding process in selecting the compensation survey service provider, and we find that the Company's selection of this provider was reasonable.

---

160 The Company did not conduct an RFP process for its reproductive services provider but did not include any costs for reproduction services in its final revenue requirement (Exhs. DPU 12-7; NG-RRP-2, Sch. 33, at 4 (Rev. 3)).

Based on our review of the RFPs and responses, we conclude that National Grid's choices regarding its remaining consultants, including attorneys, were reasonable and cost effective (Exh. DPU 12-1, Atts. 1(a) through 7(b)). We also find that National Grid gave appropriate consideration to price and non-price factors before selecting the providers that it determined would provide the best combination of price and appropriate quality of service (Exhs. DPU 12-1, Atts. 1(b) through 7(b); DPU 12-2, Att. 1 through 6; DPU 12-3). For each category, the Company appropriately selected a provider that possessed expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU 12-1, Atts. 1(b) through 7(b); DPU 12-2, Att. 1 through 6; DPU 12-3). Based on the foregoing, the Department concludes that National Grid conducted a fair, open, and transparent competitive bidding process for the remaining attorneys and consultants (Exhs. DPU 12-1, Atts. 1(b) through 7(b); DPU 12-2, Att. 1 through 6).

c. Various Rate Case Expenses

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by National Grid and finds that the invoices are properly itemized (see, e.g., Exhs. DPU 12-16, Atts. 1 through 8; DPU 12-16, Atts. 1 through 9 (Supp.); DPU 12-16, Atts. 1 through 7 (Supp. 2); DPU 12-16, Atts. 1 through 8 (Supp. 3)). In addition, the Department finds that the total costs associated with each service provider are reasonable, appropriate, and proportionate to the overall scope of work provided and were prudently incurred (see, e.g., Exhs. DPU 12-16, Atts. 1 through 8; DPU 12-16, Atts. 1 through 9 (Supp.); DPU 12-16, Atts. 1 through 7 (Supp. 2); DPU 12-16, Atts. 1 through 8 (Supp. 3)).

d. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test-year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expense so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual level of expense. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

Typically, the Department determines the appropriate period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four base distribution rate cases, including the present case, rounded to the nearest whole number. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163 n.105; D.T.E. 03-40, at 164 n.77; D.T.E. 02-24/25, at 191. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

National Grid proposes a five-year rate case expense normalization period based on the time period for its proposed PBR plan (Exh. NG-RRP-1, at 75-76).[161] The average interval between National Grid's last four base distribution rate cases is eight years.[162] As discussed in Section IV.D above, the Department has approved a PBR plan for the Company that includes a five-year term and stay-out provision. The Department has considered the term of a PBR in establishing an appropriate rate case expense normalization period. D.P.U. 17-05, at 281-282; D.P.U. 09-30, at 241; D.P.U. 07-71, at 105; D.T.E. 05-27,

---

161 The Company had initially included rate case expense on its amortization schedule (Exh. NG-RRP-5, at 4). During the proceeding, the Company revised its proposal to normalize the rate case expense (Exhs. NG-RRP-2, Sch. 33, at 4 (Rev. 3); NG-RRP-5 at 4 (Rev. 3); Tr. 1, at 88-90; Tr. 4, at 515-516).

162 In addition to the current filing, Boston Gas' prior base distribution rate filings were D.P.U. 17-170, D.P.U. 10-55, and D.P.U. 03-40 (Exh. DPU 12-20). Between D.P.U. 20-120 and D.P.U. 17-170, the interval is 2.99 years; between D.P.U. 17-170 and D.P.U. 10-55, the interval is 7.58 years; and between D.P.U. 10-55 and D.P.U. 03-40, the interval is 7.00 years. The sum of these intervals divided by three and rounded to the nearest whole number results in a normalization period of six years (17.58/3 = 5.86). The former Colonial Gas' prior base distribution rate fillings were D.P.U. 17-170, D.P.U. 10-55, and D.P.U. 93-78. Between D.P.U. 20-120 and D.P.U. 17-170, the interval is 2.99 years; between D.P.U. 17-170 and D.P.U. 10-55, the interval is 7.58 years; and between D.P.U. 10-55 and D.P.U. 93-78, the interval is 17.00 years. The sum of these intervals divided by three and rounded to the nearest whole number results in a normalization period of nine years (27.58/3 = 9.19). The average of Boston Gas' interval and the former Colonial Gas' interval is 7.55 years (rounded to eight).

at 163-164; D.T.E. 03-40, at 163; D.T.E. 01-56, at 75; D.P.U. 96-50 (Phase I) at 78. In addition, the Department has found that the term of a PBR that prevents a company from filing a new base distribution rate case for a predetermined period provides a more representative basis for establishing a rate case expense normalization period. D.P.U. 17-05, at 282; D.P.U. 96-50 (Phase I) at 78. Accordingly, the Department finds that a five-year normalization period is appropriate.

e. Conclusion

The Company proposed and the Department has accepted a final rate case expense of $2,967,496 (Exh. NG-RRP-2, Sch. 33, at 4 (Rev. 3)). Based on a five-year normalization period, the annual level of rate case expense to be included in the Company's cost of service is $593,499 ($2,967,496 divided by five years). The annual level of rate case expense approved in this proceeding is reflected in Schedule 2 below.

IX. EXOGENOUS COST PROPERTY TAX PROPOSAL

A. Introduction

As noted in Section VIII.I.1 above, certain municipalities in the Company's service area use the NBV method to assess property taxes, while other communities use the Hybrid RCNLD/NBV method. In 2011, the Supreme Judicial Court upheld a decision by the Appellate Tax Board that approved the City of Boston's assessment of Boston Gas personal utility property based on weighing NBV value equally with RCNLD. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). More recently, in a Rule 1:28 Memorandum Decision, the Massachusetts Appeals Court upheld the same assessment method used by the City of Boston as it pertained to NSTAR Electric Company's personal utility property. NSTAR Electric Company v. Assessors of Boston, 94 Mass. App. Ct. 1123 (2019). NSTAR Electric appealed to the Supreme Judicial Court, which declined the application for further appellate review. NSTAR Electric Company v. Assessors of Boston, 482 Mass. 1102 (2019).

In addition to these decisions, on March 26, 2019, the Massachusetts Department of Revenue's ("DOR") Division of Local Services issued a Local Finance Opinion detailing a change in guidance from the Bureau of Local Assessment ("BLA") on the appropriate method of valuation for purposes of local property tax assessment (Exh. DPU-1; RR-DPU-34, Att. 1). In the opinion, the BLA notes that, based on the aforementioned court decisions, it would accept a valuation method that gives equal weight to personal utility property's NBV and the property's RCNLD value (Exh. DPU-1, at 3; RR-DPU-34, Att. 1, at 3). DOR subsequently revised its certification guidelines to require assessors to "identify the existence of special circumstances that indicate a fair market value in excess of net book" and "show why special circumstances would influence a buyer to pay more than [NBV] for utility assets" (Exh. NG-PML-2, at 43-44).

B. Company Proposal

National Grid proposes to treat a municipality's transition to the Hybrid RCNLD/NBV method as an exogenous event and to recover property tax expense increases attributable to the Hybrid RCNLD/NBV method through the exogenous event provision in the Company's PBR mechanism, subject to the requisite threshold of significance (Exhs. NG-PML-1, at 17;

NG-PP-10, proposed M.D.P.U. No. 56, § 10.0; Tr. 7, at 843-844). In support of the proposal, National Grid states that all municipalities within its service area are in the process of transitioning to the Hybrid RCNLD/NBV method, which will increase the Company's property valuation and property tax expenses (Exh. NG-PML-1, at 17). At the time of initial filing in the instant proceeding, the Company indicated that eleven of the 131 municipalities in its service area had transitioned to the Hybrid RCNLD/NBV method, which resulted in incremental property tax expenses of $7,973,229 annually (Exhs. NG-PML-1, at 14; WP NG-RRP-9j (Rev. 2); DPU 37-6; RR-AG-9).[163] The Company stated that it had paid the incremental property taxes in each municipality, had sought tax abatements in seven of the municipalities, reached a settlement with one municipality, and had made appropriate filings to preserve its appellate rights with the Appellate Tax Board (Exhs. DPU 37-6; DPU 37-6 (Supp.)). The Company's proposal is intended to apply prospectively to those municipalities that adopt the Hybrid RCNLD/NBV method after the date of this Order (Exhs. NG-PML-1, at 17; DPU 37-7; DPU 47-10).[164]

---

163 These incremental property taxes are included for recovery in the Company's property tax expense (Exh. DPU 37-7). See also Section VIII.I above.

164 National Grid states that, although the proposal is intended to apply prospectively, the Company would apply any abatement of property taxes from a settlement with a municipality that has already adopted the Hybrid RCNLD/NBV method for FOL filing purposes as of fiscal year 2022, when determining if the net change due to the Hybrid RCNLD/NBV method exceeds the exogenous cost threshold (Exhs. DPU 37-7; DPU 47-10).

C. Positions of the Parties

1. Attorney General

As noted in Section VIII.I.2.a above, the Attorney General argues that the Department should reject the recovery of incremental costs associated with the Hybrid RCNLD/NBV method because the higher property valuation, upon which these costs are based, benefits shareholders and not ratepayers (Attorney General Brief at 30-31, 134-137; Attorney General Reply Brief at 65-66). Further, the Attorney General claims that the incremental property taxes associated with the Hybrid RCNLD/NBV method would not be large enough to surpass the \$2.0 million significance threshold established in the proposed exogenous cost factor (Attorney General Brief at 31, citing Exh. NG-PBRP-1, at 25 (Rev.)). For example, the Attorney General posits that if a municipality's property taxes increase by 32 percent, then the incremental tax increase must be \$6,250,000 or greater (Attorney General Brief at 31). According to the Attorney General, only the City of Boston, which already has transitioned to the Hybrid RCNLD/NBV method, would incur incremental property taxes greater than the significance threshold in the exogenous event provision of the PBR mechanism (Attorney General Brief at 31, citing Exh. NG-RRP-2, Sch. 7, at 6-8 (Rev. 1)). Therefore, she concludes, because no other municipality tax assessment would trigger recovery of incremental property taxes through the PBR mechanism, there is no need for exogenous treatment for these costs (Attorney General Brief at 31).

The Attorney General also asserts that contrary to the Company's contentions, there is no reasonable basis to conclude that DOR is requiring municipalities to use the Hybrid

RCNLD/NBV method (Attorney General Reply Brief at 65-66 & n.41). The Attorney General contends that DOR's guidelines provide several valuation methods that are available, including the Hybrid RCNLD/NBV method (Attorney General Reply Brief at 65-66 & n.41, citing Exh. DPU-1, at 3; Tr. 3, at 382-385).

2. TEC

TEC argues that the RCNLD method employs the use of hypothetical scenarios that are difficult to duplicate "in the real world" (TEC Brief at 6). Further, TEC contends that assessors' lack of engineering backgrounds and obsolete materials used in the Company's current infrastructure result in considerable variation and arbitrariness among municipalities in the valuation of utility assets (TEC Brief at 7). As a result, TEC notes that the Company is left to engage in ad hoc challenges to "home brewed" valuation methods used by the municipalities (TEC Brief at 6-7). According to TEC, these challenges result in a drain on Company resources and raise issues of fairness among municipalities and transparency and affordability for ratepayers (TEC Brief at 7).

Based on these considerations, TEC argues that while the transition to the Hybrid RCNLD/NBV method "likely qualifies as an exogenous cost," the Department must require documentation that a standardized and transparent approach to the valuation of utility assets has been followed prior to approval for exogenous cost recovery to avoid such ad hoc settlements between the Company and municipalities (TEC Brief at 6-7). TEC asserts that a standard valuation method ensures exogenous cost recovery and less resistance from the Company, and it would benefit smaller municipalities and those lacking the resources to engage external valuation consultants (TEC Brief at 7-8). According to TEC, the Department can use leverage via the approval of exogenous costs to force the adoption of a standardized method (TEC Brief at 7).

3. Company

The Company argues that the Hybrid RCNLD/NBV method causes significant increases in assessed value compared to the NBV method (Company Reply Brief at 47, citing Exhs. NG-PML-1, at 14; RR-AG-10; Tr. 3, at 376-377). The requirement to pay these incremental property taxes, the Company asserts, is outside of its control (Company Reply Brief at 47, citing D.P.U. 15-155, at 214-215). Further, the Company argues that DOR has mandated that all municipalities transition to the Hybrid RCNLD/NBV method (Company Brief at 155, citing Exh. NG-PML-1, at 12; Company Reply Brief at 47-48, 50, citing Exhs. NG-PML-1, at 12-13; NG-PML-3; DPU 25-5; Tr. 3, at 380-381, 382-383). In this regard, the Company maintains that every five years, each municipality is required to obtain a DOR certification of the real estate and personal property under the municipality's jurisdiction, including utility personal property (Company Brief at 155, citing Exh. NG-PML-1, at 15). The Company contends that DOR now requires a municipality to transition to the Hybrid RCNLD/NBV as a prerequisite to receiving another five-year certification once the existing certification expires (Company Brief at 155, citing Exhs. NG-PML-1, at 13, NG-PML-2; Company Reply Brief at 48, citing Exhs. NG-PML-1, at 13; Tr. 3, at 382-383). The Company claims that since the initial filing in this proceeding, 47 additional municipalities have transitioned to the Hybrid RCNLD/NBV method and many more will continue to do so (Company Reply Brief at 48-50, citing Exhs. NG-PML-1, at 14; Tr. 3, at 354; RR-AG-9; RR-AG-10).

Finally, the Company argues that the incremental property taxes resulting from the adoption of the Hybrid RCNLD/NBV method will qualify as an exogenous event under the PBR mechanism based on the cumulative costs for the year, not on a town-by-town basis (Company Brief at 69, citing Exh. DPU 54-4). Thus, for example, the Company asserts that the incremental property taxes associated with the eleven municipalities who had transitioned to the Hybrid RCNLD/NBV method before the initial filing in this proceeding would exceed the significance threshold in the exogenous event provision of the PBR mechanism (Company Brief at 69, citing Exh. DPU 5-4, at 2).

D. Analysis and Findings

As noted above, National Grid seeks to treat a municipality's transition to the Hybrid RCNLD/NBV method as an exogenous event and to recover property tax expense increases attributable to the Hybrid RCNLD/NBV method through the "Exogenous Events" provision in the Company's PBR mechanism, subject to the requisite threshold of significance (Exhs. NG-PML-1, at 17; NG-PP-10, proposed M.D.P.U. No. 56, § 10.0; Tr. 7, at 843-844). To qualify as an exogenous event under the Company's proposed PBR tariff provision, the following criteria must be met:

(1) the cost must be beyond the Company's control and are not reflected in GDP-PI;

(2) the cost arises from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments;

> (3) the change is unique to the natural gas distribution industry as opposed to the general economy; and
>
> (4) the change exceeds a significance threshold that is noncumulative (i.e., exogenous costs cannot be grouped together into a single total for purposes of determining whether the threshold has been met).

(Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 10.0).[165, 166] Further, the proposed tariff provides that the significance threshold for exogenous event cost recovery is $2.0 million for each individual event in the first PBR year ending September 30, 2022, and thereafter, shall be adjusted annually based on changes in GDP-PI (Exh. NG-PP-10, proposed

---

165 The Department notes that these criteria are consistent with how we have defined exogenous costs, which are positive or negative cost changes actually beyond the Company's control and not reflected in the GDP-PI. D.P.U. 17-05, at 395-396, citing D.P.U. 94-50, at 172-173. These include, but are not limited to, incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 17-05, at 396, citing D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. Importantly, the Department has cautioned against expansion of these categories to a broader range. D.P.U. 17-05, at 396, citing D.P.U. 96-50 (Phase I) at 290-291; D.P.U. 94-158, at 61-62. In addition, the Department has found that exogenous cost recovery must be subject to a significance threshold that is noncumulative (i.e., exogenous costs cannot be combined into a single total for purposes of determining whether the threshold has been met). D.P.U. 17-05, at 396, citing D.T.E. 01-56, at 22-23; D.T.E. 99-19, at 26; D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 173.

166 Further, the Company's proposed tariff provides that incremental costs that the Company incurs as a result of mandated changes in law, regulations, requirements, standards or practices relating to gas-safety directives arising from the National Transportation Safety Board, the U.S. Department of Pipeline and Hazardous Materials Administration, the Department, or any investigation conducted on behalf of the Department by an outside consultant or expert shall be eligible for exogenous event recovery, subject to the significance threshold (Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 10.0).

M.D.P.U. No. 56, § 10.0). As noted in Section IV.D.8.c above, the Department has accepted the Company's proposed definition of an exogenous event, with one amendment,[167] and the $2.0 million significance threshold.

The Company proposes that, for purposes of meeting the significance threshold it would combine the amount of incremental property taxes in any given year that result from the cities and towns adopting the Hybrid RCNLD/NBV method (Exhs. NG-PML-1, at 18; DPU 47-10; Tr. 7, at 841-843). The Company reasons that because incremental property taxes arise from a single "event or issue" (i.e., the municipalities transitioning to the Hybrid RCNLD/NBV method) in any given year, the total annual incremental property taxes should qualify for recovery under the exogenous cost provision so long as the significance threshold is met. We disagree.

Based on the clear language of the proposed tariff, and the Department's traditional definition of exogenous costs, we find that to qualify for recovery as exogenous costs, the incremental property taxes must exceed a significance threshold of $2.0 million that is noncumulative (i.e., exogenous costs cannot be grouped together into a single total for purposes of determining whether the threshold has been met) (Exhs. NG-PML-1, at 18; NG-LRK-1, at 8; NG-PBRP-1, at 25; NG-PP-10, proposed M.D.P.U. No. 56, § 10.0(4)).

---

167 As discussed in Section IV.D.8.c above, the Department directed the Company to include the term "regional" in the definition of the relevant industry in subsection (3) of the definition set forth in the Company's proposed PBR tariff (Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 10.0). That amendment does not impact our findings in this section.

See also, D.P.U. 18-150, at 421-422 (requiring a single storm event (as opposed to multiple storms) to exceed $30.0 million in costs as a condition for exogenous cost recovery); D.P.U. 17-05, at 558-559 (same). We are not persuaded by the Company's reasoning that multiple municipalities adopting the Hybrid RCNLD/NBV method at different times over the course of a year amount to a single event for exogenous cost purposes. Rather, the Department concludes that the Company's proposed aggregation of incremental property taxes from multiple municipalities to obtain a single total for the purposes of meeting the significance threshold is cumulative in nature. As such, the Department finds that the Company's proposal does not satisfy the criterion in its tariff that "the change exceeds a significance threshold that is noncumulative" (Exh. NG-PP-10, proposed M.D.P.U. No. 56, § 10.0(4)). If, however, during the five-year PBR term an individual city or town adopts the Hybrid RCNLD/NBV method or another valuation method that results in incremental property taxes in excess of $2 million, the Company may seek recovery of these costs through the exogenous cost provision.

While we are not persuaded that municipalities are mandated to transition to the Hybrid RCNLD/NBV method, the Department recognizes it is likely that more municipalities in the Company's service area will transition away from the NBV method and adopt other valuation methods, including the Hybrid RCNLD/NBV method (Exhs. NG-PML-2, at 43-44; DPU-1, at 3; RR-DPU-34, Att. 1, at 3).[168] In this regard, we acknowledge the

---

[168] The record is unclear as to the current number of cities and towns in the Company's service area using the Hybrid RCNLD/NBV method. During the proceedings, National Grid stated that 58 additional municipalities (in addition to the eleven

aforementioned decisions of the Supreme Judicial Court and Massachusetts Appeals Court, as well as BLA's and DOR's current treatment of the Hybrid RCNLD/NBV method.[169] Based on our assessment of a number of additional municipalities in the Company's service area that could adopt the Hybrid RCNLD/NBV method, or some other alternative to NBV, we

---

municipalities identified in the initial filing) had transitioned away from the NBV method, though the Company later noted it was unsure whether any of these transitioning municipalities had, in fact, adopted the Hybrid RCNLD/NBV method (Exh. DPU 37-6 & Att. (Supp.); Tr. 3, at 354; RR-AG-10). On brief, the Company claims 47 of the 58 municipalities had transitioned to the Hybrid RCNLD/NBV method (Company Reply Brief at 47).

169 In Boston Gas Company v. Board of Assessors, 458 Mass. 715, 722-723 (2011), the Supreme Judicial Court based its analysis of a board of assessors' valuation method for taxes, in part, on the Department's treatment of acquisition premiums in rates. An acquisition premium is generally defined as representing the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service and the net depreciated cost of the acquired plant to the previous owner. Mergers and Acquisitions, D.P.U. 93-167-A at 9 (1994). When a regulated utility is involved in a merger or acquisition transaction that results in an acquisition premium, the utility records the acquisition premium in a capital account (Goodwill) with a corresponding entry to an intangible asset account. The Department considers individual merger or acquisition proposals that seek recovery of an acquisition premium, on a case-by-case basis. D.P.U. 14-120, at 107-108; D.T.E. 98-31, at 38; Eastern Enterprises and Essex County Gas Company, D.T.E. 98-27, at 61 (1998); D.P.U. 93-167-A at 18-19. Recovery of acquisition or merger related costs is dependent on a showing of quantifiable benefits that outweigh the transaction and acquisition premium costs. Liberty Utilities/Blackstone Gas Company, D.P.U. 20-03, at 15 (2020); D.P.U. 14-120, at 107-108. If the Department approves the utility's recovery of the acquisition premium expense amortized in rates, the utility writes down the intangible asset as the acquisition premium is recovered in rates over time, generally amortized over the remaining life of the asset. D.P.U. 14-120, at 107-108; D.T.E. 98-31, at 38; D.T.E. 98-27, at 61; D.P.U. 93-167-A at 18-19. Under Department accounting and ratemaking for an acquisition, rate base is not involved, and no return is earned on the acquisition premium. See D.P.U. 10-55, at 473 n.299 (stating that acquisition premiums should be excluded from rate base).

recognize that it is unlikely that the significance threshold would be triggered by one municipality's adoption of the Hybrid RCNLD/NBV method or any alternative valuation method (see, e.g., RR-AG-10 & Att. 1 (identifying 58 additional municipalities that the Company claims adopted an alternative to the NBV valuation method)). Nevertheless, we will allow the Company to maintain the foregoing tariff provision through the duration of the PBR term.

Finally, we note that the Department remains willing to evaluate future proposals for recovery of incremental property taxes incurred as a result of the Hybrid RCNLD/NBV method, or any other valuation method that replaces the NBV method. We expect well-crafted proposals that demonstrate why special ratemaking treatment is needed and that strike an appropriate balance between a petitioner's need to recover these costs in between base distribution rate proceedings and the annual bill impacts on ratepayers.[170]

X. LNG LIFE-CYCLE INTEGRITY PROJECTS

A. Introduction

National Grid states that it is pursuing service life-extending upgrades at its seven LNG storage facilities in Boston, Lynn, Salem, Haverhill, South Yarmouth, Tewksbury, and

[170] The Department appreciates TEC's comments on brief regarding a standardization valuation method across municipalities (TEC Brief at 6-7). The Department has reviewed the limited record on this issue, as well (Exh. TEC 1-1; Tr. 3, at 364-378; RR-TEC-1). We encourage the Company and municipalities to work together to maintain transparency when it comes to increased property tax assessments. At this time, however, the Department is not inclined to issue any directives in this regard. To the extent the Company files for exogenous cost recovery, it will be required to provide requisite documentation to support recovery of the incremental property taxes.

Wareham ("Life-Cycle Integrity Projects") (Exh. NG-GSC-1, at 45). The Company relies on the LNG facilities to meet supply requirements during the peak period and to provide additional system pressure to its distribution system during the non-peak period (Exh. NG-GSC-1, at 45). The Company points to a Dynamic Risk Report recommendation to upgrade the LNG facilities to prepare for peak shaving and potential supply shortages (Exh. NG-GSC-1, at 46). Further, the Company asserts that upgrading its LNG facilities will reduce operational and safety risks, increase plant reliability, and provide an avoided supply interruption benefit to consumers (Exh. NG-GSC-1, at 46). The Company estimates the total cost of the Life-Cycle Integrity Projects to be $557 million for the period of 2021 through 2026 (Exh. NG-GSC-1, at 47; NG-GSC-8).

The Company currently recovers a fixed amount of the annual revenue requirement associated with LNG investment through the Production and Storage ("P&S") allowance in the Gas Adjustment Factor ("GAF") found in the Cost of Gas Adjustment ("CGA") tariff (Exh. NG-GSC-1, at 51; M.D.P.U. No. 2.3, § 6.06).[171] The P&S allowance currently allows National Grid to recover a fixed amount of annual LNG revenue requirement as determined in the Company's most recent base distribution rate case (Exh. NG-GSC-1, at 51).

[171] The revenue requirement associated with LNG investment includes O&M, return on investment, return of investment, property taxes, and an allocable share of administrative and general expenses, general plant, and other common costs (Exh. NG-GSC-1, at 51; Tr. 6, at 671-672).

B. Company Proposal

The Company currently recovers $19,519,293 in annual LNG revenue requirement through the P&S component of the GAF (Exh. NG-PP-4(b) at 10). The Company seeks to increase the fixed amount to $46,382,185 (Exhs. NG-RRP-2, Sch. 1, at 1 (Rev. 3); NG-PP-4(b) at 10; DPU 10-8 & Att.; DPU 27-2 & Att.; DPU 40-2)).

National Grid submits, however, that the proposed fixed revenue requirement will not recover sufficient revenue associated with the higher level of investment that the Company intends to spend on upgrading its LNG facilities (Exh. NG-GSC-1, at 51). Further, National Grid states that operating under a PBR plan for the next five years would prevent the Company from filing a base distribution rate case to recover the added expenses incurred associated with the Life-Cycle Integrity Projects (Exhs. DPU 7-4, at 1; DPU 7-5; DPU 27-6, at 2; DPU 53-12, at 1). Moreover, the Company notes that annual PBR adjustments would not apply to the P&S allowance and, even if the adjustments did apply, they would not provide sufficient revenue to recover the capital costs associated with its LNG investments (Exhs. NG-GSC-1, at 52; NG-PBRP-1, at 32; NG-PBRP-1, at 30-31 (Rev.); DPU 7-4).

Based on these considerations, National Grid proposes revisions to the P&S component of the CGA tariff that would allow the Company to recover Life Cycle Integrity Projects-related capital investment through an adjustment to the P&S allowance for the duration of the PBR plan (Exhs. NG-GSC-1 at 52; NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 4-6). Specifically, under National Grid's proposal, the Company would continue to recover the fixed amount of LNG revenue requirement, and, if calendar year spending for such investments exceeds $60 million, also recover the annual revenue requirement associated with the Life Cycle Integrity Projects-related capital investments (Exhs. NG-GSC-1 at 52-53; NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 5-6; DPU 27-3, at 2; Tr. 6, at 672).[172] Further, if the Company spends more than $60 million on the Life-Cycle Integrity Projects-related capital investment in a calendar year, the proposed tariff changes would allow an adjustment for LNG-related O&M expenses in that year (Exh. NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 6; Tr. 6, at 677). This O&M-related adjustment includes the annual PBR percentage increase applicable for the year in which the O&M adjustment will take effect (Exh. NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 6; Tr. 6, at 677). If National Grid spends $60 million or less on Life-Cycle Integrity Projects-related capital investment in a calendar year, the Company will recover the P&S allowance approved by the Department in the prior year (Exh. NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 5; DPU 27-2; DPU 27-3, at 2).

Under the Company's proposal, if the Life-Cycle Integrity Projects-related capital investment spending threshold is triggered in a calendar year beginning with calendar year 2021, National Grid would file by June 15th of the following year for an adjustment to the P&S allowance, as described above (Exh. NG-GSC-1, at 54). In its June 15th filing, among

---

172 The Company proposes to revise only the peak-period GAF to reflect the supply-related costs of the LNG facilities upgrades (Exhs. NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 4-5; DPU 14-11; DPU 27-5).

other items, the Company would provide the following to demonstrate that the investments were prudent and that the plant constructed is used and useful: (i) calendar year charges to in-service projects; (ii) project documentation; (iii) project authorization; (iv) variance analysis; and (v) invoice summaries (Exh. NG-GSC-1, at 54). Thus, the Company is not seeking project approval or cost recovery as part of the instant proposal (Exh. NG-GSC-1, at 52).

C. Positions of the Parties

1. Attorney General

The Attorney General asserts that the Department should reject the Company's Life-Cycle Integrity Projects-related capital investment plan and the associated proposed "capital tracker" (i.e., modification of the GAF formula) for several reasons. First, the Attorney General argues that National Grid's Life-Cycle Integrity Projects proposal represents LNG spending levels significantly higher than the amount that the Company has spent on LNG modernization since 2010 (Attorney General Brief at 89-90, citing Exhs. AG-RW-1, at 39-41; DPU-AG 3-1; DPU-AG 3-2). The Attorney General asserts that relatively consistent levels of spending on its LNG facilities over time is a more prudent approach, which may induce the Company to maintain its LNG facilities rather than pursue comparatively expensive wholesale replacement of structures (Attorney General Brief at 91, citing Exh. AG-RW-1, at 41-42).

Next, the Attorney General claims that the Company failed to provide adequate justification for the LNG projects, particularly the projects that replace existing facilities

(Attorney General Brief at 91, citing Exh. AG-RW-1, at 42). In particular, the Attorney General contends that the Company's proposed $172 million South Yarmouth LNG plant modernization project lacks sufficient analysis or justification for the proposed level of spending (Attorney General Brief at 91-92, citing Exhs. AG-RW-1, at 42-43, 48; AG 23-2).[173] The Attorney General assert that the South Yarmouth plant would have benefitted from consistent levels of spending over its service life rather than wholesale replacement after years of alleged deterioration and neglect (Attorney General Brief at 91-92, citing Exh. AG-RW-1, at 42-44).[174]

Third, the Attorney General argues that National Grid's proposed LNG "capital tracker" creates unreasonable incentives for the Company to unnecessarily increase capital investment instead of managing costs by minimizing spending on necessary projects, deferring projects, or maintaining existing infrastructure (Attorney General Brief at 93). According to the Attorney General, capital trackers in general incentivize a company to increase costs recoverable through the reconciling charge because the company's earnings are directly affected by the flow of the carrying costs in an immediate fashion, including equity

---

173 The Attorney General cites to the Company's proposed Mid-Cape Replacement Project as an example of documentation that she considers necessary to include for rate base recovery: alternatives analysis, detailed descriptions, required permits, risk assessments, maps, and cost estimate data (Attorney General Brief at 91, citing Exh. AG-RW-1, at 42).

174 The Attorney General also cites to an LNG plant of similar age owned by Philadelphia Gas Works that she claims does not require extensive upgrades as the South Yarmouth plant (Attorney General Brief at 92, citing Exhs. AG-RW-1, at 43, 48; NG-AG 1-62).

return on the investments (Attorney General Brief at 93). In this regard, the Attorney General takes issue with the Company's proposed spending threshold, and she contends that the Company has an incentive to spend more money to ensure that it exceeds the $60 million threshold and triggers the capital tracker (Attorney General Brief at 93). Finally, the Attorney General argues that the annual increase in base rates under the PBR plan will provide sufficient dollars to recover LNG-related costs and that the proposed capital tracker, if approved, would double recover investment (Attorney General Brief at 93; Attorney General Reply Brief at 10 n.9).

For these reasons, the Attorney General asserts that the Department should reject the Company's proposed Life-Cycle Integrity Projects-related capital investment plan and the associated proposed capital tracker. Notwithstanding this position, the Attorney General also asserts that the Department should direct the Company to provide detailed, project-level costs and justifications for all proposed LNG projects and alternatives analyses for why a full replacement is necessary instead of less expensive strategies (Attorney General Brief at 93-94, citing Exh. AG-RW-1, at 45).

2. Company

The Company argues that the proposed ratemaking mechanism applicable to the Life-Cycle Integrity Projects-related capital investments is necessary due to the magnitude of the planned investment over the next five years (Company Brief at 34). Further, the Company claims that the annual adjustments contemplated under the proposed PBR mechanism would not apply to the Life-Cycle Integrity Projects-related capital investments and would not be sufficient to cover this level of investment (Company Brief at 34, 36, citing Exh. NG-PBRP-1, at 30-31). According to National Grid, neither current rates nor any aspect of the PBR adjustment account for future LNG refurbishment projects (Company Reply Brief at 36, citing Attorney General Brief at 93). Thus, the Company asserts that it cannot commit to a five-year stay-out provision as part of the proposed PBR plan without a separate mechanism designed to recover the Life-Cycle Integrity Projects-related capital investments (Company Brief at 34, citing Exh. NG-PBRP-1, at 30-31).

The Company stresses that it is not asking for approval and cost recovery for these Life-Cycle Integrity Projects-related capital investments at this time (Company Brief at 35). As such, National Grid rejects the Attorney General's assertion that the Company must provide clear and specific justification for the proposed projects in the instant filing, as opposed to when the projects are presented to the Department for prudency review (Company Brief at 35, citing Exhs. NG-GSC-Rebuttal-1, at 39-41; DPU 53-12; DPU 53-14, at 3).

Further, National Grid disputes the Attorney General's characterization of the proposed ratemaking mechanism as a capital "tracker," and notes that the Company must first meet a certain spending threshold for any recovery to occur (Company Brief at 35-36). National Grid also rejects the notion that denying the proposal would better incent the Company to control its LNG infrastructure costs and to invest in maintaining its existing LNG infrastructure to avoid wholesale replacement whenever possible (Company Brief at 35, citing Attorney General Brief at 93). In this regard, the Company argues that the Attorney General ignores the nature of the planned "life-cycle" refurbishments and the fact that the need for the planned upgrades cannot be avoided or substantially modified through better incentives for cost control (Company Brief at 36).

D. Analysis and Findings

As an initial matter, no intervenor has challenged the Company's proposal to increase the annual fixed amount of LNG revenue requirement recovered through the P&S component of the GAF to $46,382,185 (Exhs. NG-RRP-2, Sch. 1, at 1 (Rev. 3); NG-PP-4(b) at 10; DPU 10-8 & Att.; DPU 27-2 & Att.; DPU 40-2). The Department has reviewed National Grid's proposal and supporting exhibits and we find that the Company's requested LNG revenue requirement increase is reasonable, appropriate, and supported by record evidence (Exhs. NG-RRP-2, Sch. 1, at 1 (Rev. 3); NG-PP-4(b) at 10; DPU 10-8 & Att.; DPU 27-2 & Att.; DPU 40-2). Accordingly, the Department approves this aspect of the Company's filing. We now turn to the Company's Life-Cycle Integrity Projects cost-recovery proposal.

In D.P.U. 17-170, at 14, 26-33, the Department rejected the Company's request to establish a fully reconciling mechanism to recover costs associated with capital investments and O&M processes that were intended to enhance the safety and reliability of the gas distribution system. The investments included LNG modernization and reinforcement projects, pipeline replacements, and location-specific gas system reinforcements.
D.P.U. 17-170, at 14.

While the Department recognized the importance of such investments, we found that special ratemaking treatment for cost recovery was unnecessary. In particular, the Department determined that the Company: (1) intended to make the capital investments irrespective of approval of the requested reconciling mechanism; (2) failed to demonstrate that the reconciling mechanism would assist in mitigating any risk to the distribution system posed by severe weather; and (3) failed to demonstrate an inability to finance the projects (either through long-term debt or continued sales) without the requested reconciling mechanism. D.P.U. 17-170, at 30-32. Further, the Department found that National Grid's GAF and GSEP provided annual recovery of costs for replacement of LNG facilities and leak-prone pipe, respectively, in which several of the Company's projects may be eligible for recovery. D.P.U. 17-170, at 32. Thus, implementation of the Company's proposed reconciling mechanism would leave even fewer projects to be recovered through traditional ratemaking. D.P.U. 17-170, at 32. The Department concluded "that, in this case, traditional ratemaking policies allow National Grid to make necessary infrastructure investments in a way that is efficient and equitable for both shareholders and ratepayers." D.P.U. 17-170, at 33, citing D.P.U. 09-39, at 80-81.

In the instant case, National Grid seeks to implement changes to its current GAF tariff to recover through the P&S allowance, capital and O&M costs associated with upgrades to specific LNG facilities (Exhs. NG-GSC-1 at 52; NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 4-6). Thus, unlike the circumstances presented in D.P.U. 17-170, the Company is not proposing to create an entirely new reconciling mechanism. Further, as the proposal in the instant case is confined to investments at specific LNG facilities, it is more targeted than the one presented in the previous base distribution rate proceeding. Nevertheless, rather than wait until its next base distribution rate proceeding, National Grid proposes to recover costs associated with the Life-Cycle Integrity Projects through the P&S component of the Company's GAF during the term of its proposed PBR plan. Thus, we find that this proposal is a departure from traditional ratemaking, and, therefore, the Company must demonstrate that special ratemaking treatment, as opposed to traditional ratemaking policies, is necessary.

National Grid has maintained throughout the proceeding that the Life-Cycle Integrity Projects will commence regardless of the Department's ruling on the Company's proposed ratemaking mechanism (Exhs. DPU 7-4; DPU 7-6; DPU 27-6). The Company states that the proposed investments are necessary to support operation of the LNG plants and include one-time costs for replacement of major components that have reached the end of their useful lives (Exhs. NG-GSC-1, at 46; DPU 7-4). Further, according to the Company, failure to complete these investments could potentially result in unreliable and unsafe operations of the facilities and compromise the plants' capability to support customer needs during the peak winter periods (Exh. DPU 7-4). The Department acknowledges the Company's safety concerns over its LNG facilities and strongly encourages the Company to invest in safety to satisfy the federal and state requirements for gas distribution companies.[175] As the

---

[175] In fact, the Company must provide safe and reliable gas distribution service and could face civil penalties for any violations. 49 C.F.R. Part 192; 220 CMR 100.00 through 220 CMR 113.00. See Report to the Legislature Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009) (Department's comprehensive oversight powers are to ensure reliable and safe services by gas and electric distribution companies to the public); D.P.U. 07-50, at 5 (Department goal is to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); D.P.U. 94-158, at 3 (since it was established in 1919, the goal of the Department has been to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); Electric

Department has previously stated, timely replacement of aging infrastructure addresses a problem that threatens public safety and the integrity and reliability of infrastructure built and maintained to serve the public. D.T.E. 05-27, at 49; D.T.E. 98-51, at 13.[176]

Additionally, it is important to note that the Company is seeking only approval of a cost recovery mechanism, and not project approval or actual cost recovery, as part of the instant proposal (Exhs. NG-GSC-1, at 52; NG-GSC-Rebuttal-1, at 40). Therefore, while we expect that the Company will make all necessary capital investments to ensure safe and reliable service to its customers, the Department makes no determination here regarding the Company's optimal level of capital investments or the prudency of such investments. Decisions regarding the level and types of capital investments to be made by a company rest, in large part, on company management in the exercise of sound business judgment. D.P.U. 85-266-A/85-271-A at 11; Weld, 197 Mass. 556, 560 (details of administration, not inconsistent with the legislative policy of the Commonwealth, may be left to the corporation,

---

Industry Restructuring, D.P.U. 95-30, at 6 (1995); Integrated Resource Planning, D.P.U. 94-162, at 51-52 (1995) (the Department emphasizes that electric companies are still required to provide safe, reliable, least-cost electric service to their ratepayers, even though companies will no longer be required to submit initial resource portfolios); D.P.U. 93-167-A at 4 (Department to ensure that utilities subject to its jurisdiction provide safe and reliable service at the lowest possible cost to society).

176 The foundation of the Company's basic public service obligation is to ensure that it delivers natural gas to their customers through a safe and reliable system at the lowest possible cost. Natural Gas Unbundling, D.T.E. 98-32-B, at 5 (1999). A utility company's obligation to fulfill safety requirements is absolute. D.T.E. 05-27, at 49; D.P.U. 92-111, at 10.

so long as adequate provision is made for the public). In this regard, we need not reach the merits of the Attorney General's arguments that more consistent levels of spending on LNG facilities over time is a more prudent approach, or that the Company failed to provide adequate justification for the LNG projects, particularly the projects that replace existing facilities (Attorney General Brief at 91, citing Exh. AG-RW-1, at 42). These issues are better suited for examination in a future proceeding when the Company seeks cost recovery for the Life-Cycle Integrity Projects-related capital investments and is required to demonstrate that such costs were prudently incurred.

As discussed in Section IV.D above, the Department has approved for the Company a PBR plan with a five-year term. During the PBR term, the annual PBR adjustments would not apply to the fixed P&S allowance or any additional capital spending on the subject LNG projects (Exhs. NG-GSC-1, at 52; NG-PBRP-1, at 30-31 (Rev.); NG-PBRP-1, at 32; NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 4-6). Moreover, although National Grid will recover annual PBR adjustments on other components of the revenue requirement, the Company has provided convincing evidence that the anticipated magnitude of the investment associated with the Life-Cycle Integrity Projects is such that some level of separate cost recovery during the PBR stay-out period is appropriate (Exhs. NG-GSC-1, at 47-51; NG-GSC-8; NG-PBRM-1, at 32; NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 6; DPU 5-14; DPU 7-4; DPU 7-5; DPU 7-7; DPU 7-9, at 1; DPU 27-7, Att.; AG 50-1, Att.;

Tr. 6, at 677).[177] Given these considerations, we find that National Grid has demonstrated the need for special ratemaking treatment to recover a level of LNG-related investments during the PBR term (Exhs. NG-GSC-1, at 52; DPU 7-4; DPU 7-5; DPU 27-6, at 2).

The Company proposes to recover costs associated with the Life-Cycle Integrity Projects-related capital investments through the P&S component of the GAF (Exhs. NG-GSC-1 at 52; NG-PP-10, proposed M.D.P.U. No. 2.4, § 6.06, at 4-6). We find that this method of recovery is appropriate given that these projects are supply-related investments.[178] We also find that it is important that this special ratemaking treatment does not lessen the Company's incentive to control its costs and result in higher annual bill

177 We also note that National Grid recently requested authorization to issue up to $1.5 billion in long-term debt, in part to finance the Company's capital needs. Boston Gas Company, D.P.U. 21-68, (Application for Issuance of Indebtedness at 3). In D.P.U. 21-68, the Company did not identify specific amounts attributable to LNG-related capital spending; however, in the instant case, the Company stated that it does not intend to issue more long-term debt if the instant Life-Cycle Integrity Projects cost-recovery proposal is rejected (Exhs. DPU 7-3; DPU 40-1). The financing proceeding, D.P.U. 21-68, is pending. As such, we do not consider long-term financing capabilities as a reason to reject the Company's cost-recovery proposal.

178 The Attorney General raised concerns regarding the interplay of cost recovery mechanisms and the PBR (Attorney General Brief at 19). The Department addresses this issue in Section IV.D.6 above.

impacts to customers.[179] Thus, we conclude that it is suitable to impose some degree of regulatory lag in the Company's recovery of the LNG-related costs.[180]

Based on these considerations, the Department allows the Company's Life-Cycle Integrity Projects cost-recovery proposal, but with two important modifications. First, the Company may petition the Department for recovery of the costs associated with the Life-Cycle Integrity Projects only once during the five-year PBR term.[181] The Company shall have the discretion to choose the year in which it petitions for cost recovery and shall notify the Department in writing no later than May 1 of its intention to make a filing during that year. The Company's filing must be submitted no later than June 15 of the filing year. The filing must be supported by testimony and relevant exhibits, including, but not limited to, (i) capital project details summary sheet and index; (ii) calendar year charges to in-service projects; (iii) project documentation including a project title page, project authorization,

---

179 Ratepayers are not guarantors of a company's success. Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, 368 (1986).

180 Under traditional ratemaking practice, there is a time gap between when a utility incurs a cost and when the utility can account for the change in costs through new rates. This time gap is referred to as "regulatory lag" and it provides companies with a strong incentive to invest wisely in capital projects, thereby controlling costs and reducing bill impacts on ratepayers. D.P.U. 17-170, at 32-33; D.P.U. 09-39, at 80. Because reconciling mechanisms, such as the GAF, allow dollar-for-dollar recovery from ratepayers, such mechanisms substantially reduce benefits to ratepayers associated with regulatory lag.

181 As part of its proposal, the Company noted that it was unlikely to trigger the proposed $60 million threshold in the first year of the proposed PBR mechanism and, therefore, would likely make four filings for LNG-related cost recovery (Exhs. NG-GSC-1, at 53-54; DPU 27-7, Att.).

project authorization detail form; (iv) closure report; (v) variance analysis, where applicable; (vi) blanket authorizations; (vii) a summary list of invoices and related costs per project; and (viii) a variance analysis on calendar year charges to in-service projects, where applicable (Exhs. NG-GSC-1, at 54-55; NG-GSC-Rebuttal-1, at 40-41; DPU 53-12). For each project, the Company shall also provide a detailed justification and alternatives analyses for why a full replacement was necessary instead of a less expensive strategy (Exhs. NG-GSC-Rebuttal-1, at 39-40; DPU 53-12).[182] Second, given that cost recovery will be limited to one filing during the five-year PBR term at the Company's discretion, we find that it is unnecessary to establish an annual spending threshold or a recovery cap. The Company's LNG-related capital spending will be examined as part of the Department's review of the prudency of the investments.

The Department finds that allowing the Company's proposal with the foregoing modifications strikes an appropriate balance between National Grid's need to recover Life-Cycle Integrity Projects-related costs during the PBR term and the Department's interest in ensuring that the Company invests wisely in these capital projects to control costs and reduce annual bill impacts on ratepayers. The Company shall make all appropriate tariff revisions consistent with the Department's findings and submit revised tariffs as part of the compliance filing in this proceeding.

---

182 The revenue requirement established for the approved investments in the one LNG cost recovery filing will remain unchanged until the next base distribution rate case. The only true up that will occur in the annual GAF filings is that of billed and collected revenues.

XI. NATIONAL GRID CRIMINAL INVESTIGATION

A. Introduction

On June 17, 2021, five former employees of National Grid USA's facilities department in New York were arrested on federal charges of fraud and bribery (Exhs. AG-Reopen-1, at 1, 43; AG 56-1).[183] Between 2013 and 2020, the defendants are alleged to have intentionally evaded National Grid USA's procurement controls to favor certain vendors in exchange for hundreds of thousands of dollars in bribes and kickbacks, in the form of both cash and other items of value, such as vehicles, tuition payments, home renovations, personal electronic devices, travel and vacation expenses (Exhs. AG-Reopen-1, at 1, 22; AG 56-1). The Governor of New York called for an investigation, and on June 24, 2021, the New York State Public Service Commission ("NYPSC") commenced an investigation of National Grid USA and two of its New York affiliates regarding the allegations (Exhs. AG-Reopen-1, at 1-15; AG 56-1). National Grid USA represents that it has been identified as a victim of the alleged actions and is fully cooperating with the U.S. Attorney for the Eastern District of New York ("U.S. Attorney"), the Federal Bureau of Investigation ("FBI"), and the NYPSC in this matter (Exhs. AG-Reopen-1, at 43; AG 56-1). National Grid USA also has arranged for an independent review of its internal

183 The defendants had been employed in National Grid USA's facilities department, which is responsible for activities such as building maintenance, landscaping, paving, fencing and snow removal at its downstate New York facilities (Exhs. AG-Reopen-1, at 18-19; 43; AG 56-1).

controls and procedures bearing on procurement to identify areas for improvement (Exh. AG 56-1).[184]

Based on a review of those vendor invoices, purchase orders, and contracts entered into over the three years between 2018 and 2020 where NGSC costs were allocated to Massachusetts operations, the Company identified 148 invoices with a total value of $333,546 that were implicated by the alleged actions of the five former employees (Exh. AG 56-1).[185] Of this amount, Massachusetts affiliates were allocated $36,378 in indirect costs, all of which was booked to operating and maintenance expense (Exh. AG 56-1 & Att. 2, at 17-32). During the test year, the Company was allocated $1,573 in such indirect costs from NGSC (Exh. AG 56-1).[186]

B. Positions of the Parties

1. Attorney General

The Attorney General argues that the evidence indicates that the Company's proposed cost of service may include expenses that were incurred as the result of criminal activity

---

184 The underlying facts leading to the criminal charges and NYPSC investigation are provided in the Department's Order reopening the record on this issue. D.P.U. 20-120, Interlocutory Order on Attorney General's Motion to Reopen Record (July 16, 2021).

185 These activities and the associated costs predominantly pertain to shared New York facilities that house NGSC employees who provide services to National Grid USA's Massachusetts operating companies (Exh. AG 56-1).

186 In addition to these expenses, the Company was allocated $7,833 in employee compensation costs associated with the five former employees during the test year (Exh. AG 56-1).

conducted by the five former employees (Attorney General Supplemental Brief at 7, citing Exh. AG 56-1 & Att. 2). According to the Attorney General, the Department already has recognized the need to investigate the alleged criminal activities of the five former employees and the potential effect on the rates being set in this proceeding (Attorney General Supplemental Brief at 9, citing Interlocutory Order at 10-11). Drawing on analogies to the Department's ratemaking treatment of fines and penalties, as well as costs incurred as a result of failures to comply with applicable laws and regulations, the Attorney General concludes that costs incurred as a result of criminal activities should be excluded from the Company's cost of service (Attorney General Supplemental Brief at 7-8, citing D.T.E. 03-40, at 261-262; D.T.E. 99-118, at 7 n.5; D.P.U. 88-67 (Phase I) at 142-143; Kings Grant Water Company, D.P.U. 87-228, at 18-19 (1988); Nantucket Electric Company, D.P.U. 1530, at 26 (1983); Blackstone Gas Company, D.P.U. 19830/19980, at 10 (1979)).[187] The Attorney General also maintains that costs incurred due to the criminal activity of utility company employees should be excluded from the Company's proposed cost of service for public policy reasons (Attorney General Supplemental Brief at 8).

The Attorney General contends that it is not possible at this time to determine whether the five former employees did indeed engage in criminal activity or whether any costs

---

187 The Attorney General also argues that costs associated with the alleged criminal activities may have been included in the cost of service used to set the rates that were ordered by the Department in both the Company's base distribution rate case in D.P.U. 17-170 and in the recent base distribution rate case of National Grid USA's other Massachusetts operating companies Massachusetts Electric Company and Nantucket Electric, D.P.U. 18-150 (Attorney General Supplemental Brief at 7 n.3).

incurred as a result of criminal activities are included in the Company's proposed cost of service (Attorney General Supplemental Brief at 8). The Attorney General points out that the base distribution rates from this case are expected to go into effect on November 1, 2021, and may be in effect for up to ten years under the Company's proposed PBR plan (Attorney General Supplemental Brief at 8). Therefore, the Attorney General requests that the Department open a new, separate docket to investigate the alleged criminal activities of the five former employees currently under investigation, as well as any costs associated with these criminal activities that may affect the Company and its customers (Attorney General Supplemental Brief at 8). Further, in recognition of the ongoing status of the various investigations, the Attorney General recommends that the Department wait to commence its own investigation until the U.S. Attorney, FBI, and the NYPSC have completed their investigations (Attorney General Supplemental Brief at 9). The Attorney General reasons that the ongoing investigations likely will provide valuable evidence related to the legitimacy of the charges and the identification of contracts and the associated dollar amounts that can be linked to any criminal activities, which would allow the Department to maximize administrative efficiency and ultimately allow for a more thorough and complete investigation (Attorney General Supplemental Brief at 9).

The Attorney General also urges the Department to take any other measures deemed necessary to ensure that Massachusetts customers have not and will not be harmed by any criminal activities of employees of the Company and its affiliates (Attorney General Supplemental Brief at 8, 13). As one of these measures, the Attorney General proposes that the Department establish a rate mechanism to appropriately adjust the Company's rates to account for costs resulting from the alleged criminal activities that are embedded in both its current rates and in its proposed cost of service in this case (Attorney General Supplemental Brief at 8). The Attorney General contends that the exogenous cost component of the Company's proposed PBR plan would be a suitable vehicle for passing back any overcharges to customers, provided that any threshold requirement for exogenous costs would not apply to charges resulting from criminal activity (Attorney General Supplemental Brief at 11-12). In the alternative, the Attorney General proposes that if the Department declines to establish an exogenous cost factor, with or without a PBR rate plan, in this proceeding, the Department should order the Company to add a provision to its LDAC to immediately flow back all costs determined to be associated with the criminal activities (Attorney General Supplemental Brief at 13).

2. Company

National Grid states that it takes this matter extremely seriously, and will be as informative as possible with regulators, including the Department, to ensure that any potential customer impacts associated with the alleged criminal actions are identified and addressed as quickly as possible (Company Supplemental Brief at 4-5). The Company points out, however, that the various reviews and investigations, including those of the NYPSC, are ongoing and are likely to take many months to complete (Company Supplemental Brief at 5, citing Exh. AG 56-1). Consequently, the Company contends that there is currently no basis at this time to determine whether its cost of service or rate base has been affected by the alleged criminal acts of the five former employees, and that no determination as to whether any imprudent costs were actually allocated to the Company is possible unless and until the NYPSC makes its own findings related to its investigation (Company Supplemental Brief at 2, 5).

Because of the ongoing nature of the NYPSC investigation and the small amount of expense identified at issue here (according to National Grid, approximately $9,406 allocated to it), the Company requests that the Department rule that the NYPSC investigation has no bearing on this proceeding (Company Supplemental Brief at 2, 5-7, citing Exh. AG 56-1, Att.). Rather, the Company urges the Department to defer any action until after the conclusion of the U.S. Attorney and NYPSC investigations, by which time any illegal costs would have been identified and confirmed (Company Supplemental Brief at 2-3, 6-7).

C. Analysis and Findings

It is axiomatic that payments associated with criminal activities, whether in the form of bribes or kickbacks, are not eligible for rate recovery as a matter of public policy. In this particular case, the alleged criminal conduct of the five former employees may have resulted in unwarranted payments to contractors by NGSC, the costs of which would have been allocated to NGSC's affiliates, including the Company (Exh. AG-Reopen-1, at 7-8).[188]

---

[188] Unwarranted payments are alleged to have occurred in at least two ways. First, in at least one instance a contractor is alleged to have recouped at least part of a bribe or kickback by inflating an invoice or contract (Exh. AG-Reopen-1, at 36). Second, the five former employees are alleged to have engaged in manipulative practices such as bid rigging to ensure the awarding of contracts to favored vendors (Exh. AG-Reopen-1, at 31).

Because NGSC charges are an integral part of the Company's proposed cost of service, any unwarranted NGSC expenditures would have been included in the Company's cost of service to the detriment of customers. To the extent that National Grid's rates included charges for payments to contractors that were illegal and unwarranted, they could be the basis for unjust and unreasonable rates that were established based on such costs and expenditures.

Moreover, the alleged scope of misconduct includes bid rigging, favoritism with respect to "no-bid" contracts, and other behaviors that are contrary to the best interests of National Grid, its customers, and other contractors (Exh. AG-Reopen-1, at 11, 21). These actions raise serious questions as to whether National Grid's internal controls were inadequate or were inadequately enforced to protect against excessive payments and illegal conduct by its employees. Consequently, National Grid's conduct in connection with the contracts at issue could be deemed imprudent.

While $9,406 in test-year expenses may have been affected by the alleged bribery scheme (Exh. AG 56-1 & Atts.), at least some of these costs were indisputably incurred for legitimate utility purposes. There is insufficient evidence at this time to determine whether and to what extent the $7,833 in payroll costs and $1,573 in NGSC costs allocated to the Company during the test year had been inflated as a result of the alleged criminal actions. Nevertheless, there is evidence that the alleged activities had been occurring as far back as 2013 and may have affected all of NGSC's Massachusetts affiliates (Exhs. AG-Reopen-1, at 22; AG 56-1, Att.). As acknowledged by the Company itself, further inquiry is clearly warranted (Exhs. AG-Reopen-1, at 43; AG 56-1).

Based on the foregoing, pursuant to the Department's supervisory authority over the Company, we will open an investigation into the alleged criminal activities of the five former employees currently under investigation by the U.S. Attorney, the FBI, and NYPSC, as well as any costs associated with these criminal activities that may have been passed on to the Company and its customers, as well as to other Massachusetts affiliates of National Grid USA and their customers. As part of this investigation, the Department will consider the appropriate vehicle by which any unwarranted costs would be returned to ratepayers. While the Attorney General has proposed revisions to either the exogenous cost component of the Company's PBR mechanism or its LDAC, the Department finds that examination of this issue in our to-be-docketed investigation will allow for a fuller evidentiary record on which to determine the appropriate passback vehicle for any additional costs that resulted from the alleged criminal actions.

To address this issue, the Company shall account for any expenses identified as having been incurred as a result of the alleged criminal actions of the five former employees. Such amounts shall be booked as regulatory liabilities, to be refunded to ratepayers in a manner to be determined by the Department in the to-be-docketed proceeding. See, e.g., D.P.U. 18-15, Order Opening Investigation at 5. The Department fully expects that ratepayers will be made whole for any costs resulting from criminal actions.

Finally, both the Company and the Attorney General propose that any Department investigation be deferred until the conclusion of the various investigations underway by the U.S. Attorney, FBI, and NYPSC (Company Supplemental Brief at 5; Attorney General

Supplemental Brief at 9). The Department disagrees. The U.S. Attorney and FBI investigations are focused on criminal matters, and the NYPSC investigation is focused on regulatory matters (Exh. AG-Reopen-1, at 7-15, 17-41). Determining whether a particular expense was imprudently incurred does not solely depend on whether the underlying activity was criminal in nature. Moreover, the Department is aware that criminal investigations of this nature may take years to complete, with the outcome dependent upon the judicial system. Because our role as an economic regulator is more related to the NYPSC than to either the U.S. Attorney or FBI, the Department will defer its own investigation until the conclusion of the NYPSC investigation, regardless of the status of the U.S. Attorney or FBI investigations. We find that the NYPSC investigation is likely to provide valuable evidence related to vendor contracts and the legitimacy of their underlying charges, and that deferring our own proceeding will allow for both administrative efficiency and a more thorough and complete investigation of the underlying ratemaking issues.[189]

In reaching this conclusion, the Department is confident that the NYPSC will conduct a thorough and complete investigation into the alleged activities. Nevertheless, as we noted

---

189 The alleged activities have the potential to represent a serious breach of established trust between ratepayers, the regulator, investors, and National Grid USA. Injurious practices within the parent company National Grid USA can adversely affect the Company, its ratepayers, and its investors. During the period of investigations and reviews, it is essential that National Grid USA examine its corporate governance practices and institute necessary internal controls to safeguard assets, prevent the occurrence of fraud, and ensure that its current employees and contractors are acting in an ethical and prudent manner. The Department takes issues of this nature seriously and will ensure that the Company's ratepayers are held harmless from these and any other discovered criminal activities.

in the Interlocutory Order at 11, our jurisdiction in this matter is independent from that of the NYPSC. If, at a later date, the Department determines that more proactive measures are warranted, we may commence our own independent investigation prior to the outcome of the NYPSC investigation based on our supervisory authority under G.L. c. 164, § 76.[190]

XII. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

National Grid proposes a 7.41-percent WACC, representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exhs. NG-RRP-2, Sch. 1, at 6 (Rev. 3); NG-AEB-11, at 1). The Company's WACC is based on the following elements: (1) a capital structure consisting of 46.56 percent long-term debt and 53.44 percent common equity; (2) a long-term debt cost rate of 3.86 percent; and (3) an ROE of 10.50 percent (Exhs. NG-AEB-1, at 68-69; NG-AEB-11, at 2; NG-RRP-2, Sch. 1, at 6 (Rev. 3)). The Attorney General proposes a 6.55-percent WACC based on the following components: (1) a capital structure consisting of 47.59 percent long-term debt and 52.41 percent common equity; (2) a long-term debt cost rate of 3.86 percent; and (3) an ROE of 9.0 percent (Exhs. AG-JRW-1; AG-JRW at 4).

---

190 The Department's exercise of its supervisory authority extends "to the interpretation and elaboration of the panoply of powers and duties confided to the [D]epartment." Cambridge Electric Light Company v. Department of Public Utilities, 363 Mass. 474, 494 (1973).

B. Capital Structure

1. Introduction

At the end of the test year, National Grid's capital structure included $1,836,902,000 in long-term debt and $2,611,827,000 in common equity (Exh. NG-AEB-11, at 2). The Company proposes to include an adjusted pro forma balance of $1,846,000,000 in long-term debt to reverse $9,098,000 in unamortized debt issuance expenses (Exh. NG-AEB-11, at 2). In addition, National Grid proposes an adjusted pro-forma common equity balance of $2,118,432,000 to remove $450,395,000 of goodwill and accumulated other comprehensive income and a dividend of $43,000,000 paid on September 25, 2020 (Exh. NG-AEB-11, at 2). National Grid's adjustments result in a total capitalization of $3,964,432,000 composed of 46.56 percent long-term debt and 53.44 percent common equity (Exhs. NG-AEB-1, at 9, 66; NG-AEB-11, at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that National Grid's common equity ratio is higher than the average common equity ratios employed by the Attorney General's proposed proxy group and approved for gas distribution companies (Attorney General Brief at 152, citing Exh. AG-JRW at 23). The Attorney General argues that the Department should reject the Company's proposed capital structure and instead impute a capital structure based on a common equity ratio of 52.42 percent, which represents the average common equity ratio authorized for gas companies in 2020 (Attorney General Brief at 153, citing Exh. AG-JRW at 153, 178; Attorney General Reply Brief at 41, citing Exh. AG-JRW-Surrebuttal at 25).

b. Company

National Grid contends that the Company's proposal to use its actual test-year-end capital structure with adjustments to remove unamortized debt issuance expenses, goodwill and accumulated other comprehensive income, and a dividend payment in accordance with standard ratemaking practice is consistent with Department precedent (Company Brief at 230, citing D.P.U. 19-120, at 343; D.P.U. 18-150, at 447; D.P.U. 17-05, at 615; Exhs. NG-AEB-1, at 66; NG-AEB-11, at 2). Further, the Company asserts that a capital structure with 53.44 percent common equity is very similar to common equity ratios approved recently by the Department and consistent with the equity capitalization ratios of other comparable gas distribution companies (Company Brief at 230, 242, citing Bay State Gas Company, D.P.U. 15-50, at 8 (2015) (53.54 percent common equity); Fitchburg Gas and Electric Light Company, D.P.U. 19-131, at 9 (2020) (52.45 percent common equity); D.P.U. 19-120, at 346 (54.77 percent common equity); D.P.U. 17-170, at 265-266 (53.04 percent common equity); Exhs. NG-AEB-1, at 67; NG-AEB-10; Company Reply Brief at 271, citing Exhs. NG-AEB-1, at 67; NG-AEB-10; NG-AEB-Rebuttal-1, at 80). Moreover, National Grid maintains that the proposed common equity ratio is comparable to the Company's proposed proxy group's average common equity ratio of 55.73 percent and within the range of common equity ratios in the proxy group from 48.52 percent to

63.55 percent (Company Brief at 242, citing Exhs. NG-AEB-1, at 67; NG-AEB-10; NG-AEB-Rebuttal-1, at 80).

The Company also contends that the Attorney General's proposed capital structure was calculated inappropriately based on the capital structures of the holding companies in the proxy group level rather than the operating companies (Company Brief at 242). National Grid argues that holding companies operate differently than operating companies and maintains that the Department has routinely rejected proposals to impute a capital structure based on the capital structures of holding companies (Company Brief at 242, citing D.P.U. 18-150, at 450-451, n.231; D.P.U. 13-75, at 272-273, 275-276; Exh. NG-AEB-Rebuttal-1, at 79).

3. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock,[191] and common equity. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5. The WACC is used to calculate the rate of return, which is applied to the company's rate base as part of the revenue requirement established by the Department, and it is made up of three components: (1) the cost of the

[191] National Grid's capital structure does not include preferred stock.

company's long-term debt; (2) the cost of the company's preferred stock; and (3) the ROE set by the Department. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department typically will accept a company's test-year-end capital structure, allowing for known and measurable changes. D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 174; D.P.U. 84-94, at 50. Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 428-429 (1971); High Wood Water Company, D.P.U. 1360, at 26-27 (1983); Blackstone Gas Company, D.P.U. 1135, at 4 (1982) (a company's capital structure which is composed entirely of common equity with no long-term debt varies substantially from usual utility practice); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

No party contested the proposed adjustments to National Grid's test-year-end capital structure. The Department relies on the face value of the outstanding debt, as opposed to face value less various unamortized balances, to determine long-term debt balances for ratemaking purposes. D.P.U. 18-150, at 448; D.P.U. 17-05, at 629. Therefore, we accept the Company's treatment of unamortized debt issuance costs as consistent with Department precedent (Exh. NG-AEB-11). D.P.U. 18-150, at 448; D.T.E. 03-40, at 319-324; D.P.U. 84-94, at 51-52. In addition, the Department accepts the removal of goodwill and accumulated other comprehensive income from the Company's balance of common equity as consistent with the Department's ratemaking treatment of those items (Exh. NG-AEB-11, at 2). D.P.U. 18-150, at 448-449. Lastly, the Department accepts the Company's adjustment for the dividend payment as it represents a known and measurable change to test-year-end capitalization (Exh. NG-AEB-11, at 2). D.P.U. 18-150, at 449-450.

In support of her contention that the Company's proposed common equity ratio should be rejected, the Attorney General has neither argued nor presented evidence that the Company's 53.44-percent common equity ratio deviates substantially from sound utility practice. Rather, the Attorney General merely cites to her consultant's testimony that the proposed common equity ratio is slightly higher than the average of the holding companies in her proxy group (Attorney General Brief at 152, citing Exh. AG-JRW at 23). As noted above, this fact alone does not meet the Department's standard to impute a capital structure. Further, her consultant also testified that typical equity ratios for electric utilities fall in the range from 40 percent to 50 percent, yet the Attorney General provides no reasoning to explain why a 52.41-percent common equity ratio falling just outside that range referenced for electric utilities is acceptable but a 53.44-percent common equity ratio is not (Exh. AG-JRW at 26).

Based on the foregoing analysis, we find that the Attorney General's argument is less persuasive than the Company's capital structure analysis, which demonstrates that a 53.44-percent common equity ratio is comparable to the common equity ratios of comparable operating companies and within the range of common equity ratios in the Company's proxy group from 48.52 percent to 63.55 percent (Exhs. NG-AEB-1, at 67; NG-AEB-10;

NG-AEB-Rebuttal-1, at 80). Therefore, the Department will use a long-term debt balance of $1,846,000,000 and a common equity balance of $2,118,432,000 to determine National Grid's capital structure. As shown in Schedule 5 below, the use of these balances produces a capital structure consisting of 46.56 percent long-term debt and 53.44 percent common equity.

C. Return on Equity

1. Introduction

In support of the Company's proposed 10.50-percent ROE, National Grid engaged an economic and financial consultant to provide a cost of equity analysis and recommendation (Exhs. NG-AEB-1, at 1-3; NG-AEB-2). The Company's ROE analysis considered the results of the constant growth discounted cash flow model ("DCF"); the capital asset pricing model ("CAPM"); and an expected earnings analysis on a proxy group of publicly held gas distribution companies (Exh. NG-AEB-1, at 3-4). National Grid's ROE analysis also considered the following factors in aggregate to recommend an ROE within the range of analytical results: (1) current and projected capital market conditions; (2) the Company's capital expenditure requirements; (3) regulatory environment and policies; (4) the Company's proposed PBR plan; and (5) the 2017 TCJA (Exh. NG-AEB-1, at 3-4).

National Grid selected six publicly held gas distribution companies for its proxy group[192] by applying a series of screens to the companies classified by Value Line Investment Survey ("Value Line") as natural gas distribution utilities (Exh. NG-AEB-1, at 36-37).[193] The Company also presented ROE results that included data from a seventh company, New Jersey Resources Corporation ("NJR"), which had failed to meet the screening criterion of deriving more than 70 percent of its total operating income from regulated operations by a small margin (Exh. NG-AEB-1, at 37-38). The Company's rebuttal testimony applied the DCF model, CAPM, and expected earnings analysis to a combined proxy group of nine publicly held gas distribution companies, which included all of the companies selected by the Company and all of the companies selected by the Attorney General (Exh. NG-AEB-Rebuttal-1, at 14).[194]

---

192 It is necessary to establish a group of publicly traded companies to serve as a proxy to estimate a market-based ROE because the Company is not publicly traded (Exh. NG-AEB-1, at 35).

193 The following were National Grid's selection criteria: (1) pay consistent quarterly cash dividends; (2) have investment grade long-term issuer ratings from either Standard and Poor's or Moody's; (3) have positive long-term earnings growth forecasts from at least two utility industry equity analysts; (4) derive more than 70 percent of their total operating income from regulated operations; (5) derive more than 60 percent of regulated operating income from gas distribution operations; and (6) were not parties to a merger or transformative transaction during the analytical periods relied on (Exh. NG-AEB-1, at 36).

194 The combined proxy group included the six gas companies initially chosen by National Grid as well as NJR, Chesapeake Utilities Corporation ("Chesapeake"), and NiSource, Inc ("NiSource"), which were recommended for inclusion by the Attorney General (Exhs. NG-AEB-Rebuttal-1, at 14; NG-AEB-Rebuttal-3; NG-AEB-Rebuttal-4; NG-AEB-Rebuttal-5).

In National Grid's DCF model, the required ROE equals the sum of the expected dividend yield and the expected long-term growth rate (Exh. NG-AEB-1, at 42).[195] For the expected dividend yield, the Company used the proxy companies' current annualized dividend[196] and average closing stock prices (Exh. NG-AEB-1, at 43). For the expected long-term growth rate, National Grid's consultant used the projected earnings and retention growth rates of the proxy companies provided by Zacks Investment Research ("Zacks"), Thomson First Call (provided by Yahoo! Finance) ("Thomson") , and Value Line (Exhs. NG-AEB-1, at 44; NG-AEB-Rebuttal-1, at 14). The Company excluded DCF results lower than seven percent from its analysis because equity investors would consider such returns to provide an insufficient return increment above long-term debt costs (Exh. NG AEB 1, at 43). Based on data for the combined proxy companies as of March 31, 2021, the median DCF results ranged from 8.24 percent to 11.74 percent with the exclusions and 7.50 percent to 11.74 percent for the entire proxy group (Exhs. NG-AEB-Rebuttal-1, at 14, 15; NG-AEB-Rebuttal-3).[197]

---

195 The DCF model is based on the theory that a stock's current price represents the present value of all expected future cash flows and requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate (Exh. NG AEB 1, at 42).

196 To annualize the dividend the Company applied one half of the expected annual dividend growth rate (Exh. NG-AEB-1, at 43).

197 Based on data for the Company's initial proxy companies as of September 30, 2020, the mean DCF results ranged from 9.65 percent to 11.81 percent with the Company's

The Company's CAPM included three components in calculating the cost of equity: (1) expected risk-free rates of return; (2) a market risk premium; and (3) the proxy companies' beta coefficients, which are a measure of systemic risk, from Bloomberg Professional ("Bloomberg") and Value Line (Exhs. NG-AEB-1, at 46-47, 49; NG-AEB-Rebuttal-4). For the expected risk-free rates of return, National Grid used the current 30-day average yield on 30-year U.S. Treasury bonds from Bloomberg and average projected 30-year U.S. Treasury bond yields from Blue Chip Financial Forecasts ("Blue Chip") (Exhs. NG-AEB-1, at 48; NG-AEB-Rebuttal-4). For the market risk premium, National Grid subtracted the expected risk-free rates of return from the estimated market-required returns, which the Company determined by performing a DCF analysis on Standard and Poor's ("S&P") 500 Index (Exhs. NG-AEB-1, at 49; NG-AEB-6; NG-AEB-Rebuttal-4).[198] National Grid's updated median CAPM results for the combined proxy companies ranged from 11.45 percent to 12.07 percent (Exhs. NG-AEB-Rebuttal-2, at 1; NG-AEB-Rebuttal-4, at 1-2).[199] Additionally, the Company provided the results of an

---

proposed exclusions and 8.68 percent to 11.66 percent for the entire proxy group, including NJR (Exhs. NG-AEB-1, at 45-46; NG-AEB-5).

198 The rebuttal testimony from National Grid's consultant calculated the estimated weighted growth rate using the weighted growth rates and dividend yields projected by Value Line as of March 31, 2021 (Exh. NG-AEB-Rebuttal-4). Initially, the Company relied on the estimated growth rate of the S&P 500 published in the S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, September 30, 2020 (Exh. NG-AEB-6, at 3).

199 Based on data for the Company's initial proxy companies as of September 30, 2020, the mean CAPM results ranged from 11.55 percent to 12.40 percent and

empirical CAPM ("ECAPM"), which applies a 75-percent weighting to the product of the beta coefficient and the market risk premium and a 25-perecnt weighting to market risk premium alone (Exh. NG-AEB-1, at 51). National Grid's updated median ECAPM results for the combined proxy companies ranged from 12.01 percent to 12.48 percent (Exhs. NG-AEB-Rebuttal-2, at 1; NG-AEB-Rebuttal-4, at 1-2).[200]

National Grid's expected earnings analysis is a forward-looking comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of stock (Exh. NG-AEB-1, at 53). The Company relied on projected ROEs reported by Value Line for the period from 2023 to 2025, adjusted to reflect average shares outstanding over the period (Exh. NG-AEB-1, at 53). Based on the expected earnings analysis, the mean expected return for all natural gas utilities reported by Value Line was 10.13 percent and the expected return for the Company's proxy group was 9.89 percent (Exh. NG-AEB-Rebuttal-1, at 15; NG-AEB-Rebuttal-5).[201]

11.58 percent to 12.47 percent for the entire proxy group, including NJR (Exh. NG-AEB-6).

200 Based on data for the Company's initial proxy companies as of September 30, 2020, the mean ECAPM results ranged from 12.17 percent to 12.87 percent and 12.20 percent to 12.87 percent for the entire proxy group, including NJR (Exh. NG-AEB-6).

201 Based on data available at the time of the Company's initial filing, the mean expected return for all natural gas utilities reported by Value Line was 10.23 percent and the expected return for the Company's proxy group was 9.53 percent (Exhs. NG-AEB-1, at 55; NG-AEB-7).

Based on the results of the Company's ROE estimation models and the other factors discussed above, National Grid's consultant opined that 9.75 percent to 10.70 percent represented a reasonable range of ROEs (Exhs. NG-AEB-1, at 9; NG-AEB-Rebuttal-1, at 13). After considering overall market conditions and risks specific to National Grid, the consultant determined that a 10.50-percent ROE was appropriate for the Company (Exhs. NG-AEB-1, at 9; NG-AEB-Rebuttal-1, at 13; NG-RRP-2, Sch. 1, at 6 (Rev. 3)).

The Attorney General also retained a consultant to evaluate the Company's proposed ROE and to provide an alternative cost of equity analysis and recommendation (Exh. AG-JRW at 1). The Attorney General's analysis considers the results of DCF and CAPM analyses on his proxy group of nine publicly held gas distribution companies (Exh. AG-JRW at 21, 95). The Attorney General's consultant opines that an ROE in the range of 7.6 percent to 9.1 percent is appropriate and recommends an ROE in the upper end of the range for the Company, i.e., 9.0 percent, because of the recent rise in interest rates (Exh. AG-JRW at 95). As discussed below, however, the Attorney General argues that National Grid's ROE should be set at the low end of the reasonable range, i.e., 7.6 percent, because of deficient management (Attorney General Brief at 177-178).

2. Positions of the Parties

a. Attorney General

i. ROE Estimation Models

(A) Proxy Group

The Attorney General asserts that National Grid's proxy group is too small to provide a good estimate of the required ROE (Attorney General Brief at 149, citing Exh. AG-JRW at 6; Attorney General Reply Brief at 37, 42). The Attorney General maintains that the proxy group of nine companies that her consultant employed is appropriate for National Grid (Attorney General Reply Brief at 42).

(B) Discounted Cash Flow

(1) Expected Dividend Yield

The Attorney General maintains that the Company's proxy companies' relative stock valuations and resulting dividend yields do not cause the DCF results to underestimate the market-determined cost of equity (Attorney General Brief at 149, 158-159, citing Exh. AG-JRW at 74; Attorney General Reply Brief at 37, 43). She asserts that the Company's claim presumes that the Company's analyst knows more about the stock market than market investors (Attorney General Brief at 159). In addition, she argues that if the Company's claims are true, then utility stocks are overvalued and the Company should be forecasting negative returns, which is not the case (Attorney General Brief at 159, citing Exh. AG-JRW at 74).

(2) Expected Long-Term Growth Rate

The Attorney General asserts that the Department should reject National Grid's DCF results based on two issues with the expected long-term growth rates employed by the Company (Attorney General Brief at 156). First, the Attorney General alleges that the long-term earnings growth rates of Wall Street analysts and Value Line are overly optimistic, resulting in an upward bias in cost of equity estimates (Attorney General Brief at 157-158, citing Exh. AG-JRW at 69-71; Attorney General Reply Brief at 43-46). Second, the Attorney General argues that the growth rates from Value Line can be inflated because they are based on data from a three-year base period, as evidenced by comparing the significantly higher mean Value Line growth rates for the Company's initial proxy group to the growth rates provided by Zacks and Thomson for the Company's initial proxy group (Attorney General Brief at 158, citing Exh. AG-JRW at 72).

Further, the Attorney General maintains that her consultant's DCF analysis used an appropriate growth rate of 5.25 percent based on earnings per share ("EPS"), dividends per share, book value per share, and sustainable growth rates from Value Line, an accorded primary weight to the projected EPS growth rate of Wall Street analysts (Attorney General Brief at 156, citing Exh. AG-JRW at 45-46). The Attorney General asserts that her consultant did not rely on historical data, as the Company claims, to develop the 5.25-percent growth rate (Attorney General Reply Brief at 42). Further, the Attorney General argues that it is appropriate to utilize internal growth as a measure of sustainable growth as it is the predominant component (Attorney General Reply Brief at 43). In addition, she contends that an external growth component is speculative because the calculation includes projections of a future market-to-book ratio, as well as future issues of stock (Attorney General Reply Brief at 43, citing Exh. AG-JRW-Surrebuttal at 14).

(3) Exclusions

Lastly, the Attorney General argues that the Company improperly excluded low-end DCF results from its analysis of the Company's required ROE (Attorney General Brief at 157, citing Exhs. AG-JRW at 68; NG-AEB-1, at 45; Attorney General Reply Brief at 43). She claims that the Company's asymmetrical exclusion of low-end outliers without a corresponding exclusion of high-end outliers results in an upward bias (Attorney General Brief at 157).

(C) Capital Asset Pricing Model

(1) Market Risk Premium

The Attorney General argues that the Company's proposed CAPM analysis grossly overstates National Grid's cost of equity because the consultant's calculation of the market return includes absurd and unrealistic assumptions of future economic and earnings growth (Attorney General Brief at 150, 167, 178).

The Attorney General asserts that National Grid's assumption of a 14.05-percent expected market return assumes that the future return on the U.S. stock market will be more than 40 percent higher than the ten-percent compounded annual return between 1928 and 2020 (Attorney General Brief at 163-164, citing Exh. AG-JRW at 77). She contends that National Grid's market risk premium is much larger than the market risk premium indicated by: (1) historic stock and bond return data in the 4.40 percent to 6.44 percent range; (2) market risk premium results for ex ante models in the 3.42 percent to 6.25 percent range; and (3) market risk premiums found in published studies and surveys in the 3.36 percent to 5.70 percent range (Attorney General Brief at 150, 164, citing Exh. AG-JRW-6, at 8).

Further, she maintains that the 12.27-percent long-term EPS growth rate used to calculate the market return is overstated and unrealistic (Attorney General Brief at 165; Attorney General Reply Brief at 44-46). The Attorney General contends that the evidence demonstrates that: (1) the long-term EPS growth rate forecasts of Wall Street securities analysts are upwardly biased; (2) historic EPS and gross domestic product ("GDP") growth has been in the six-percent to seven-percent range; (3) there is a direct link between long-term EPS and GDP growth; (4) future GDP growth is forecast to slow to about four percent; (5) GDP constrains corporate profits; and (6) that if the net income of the S&P 500 companies grows at 12.27-percent it would represent an absurd growth from 6.53 percent today to 68.2 percent of GDP in 2050 (Attorney General Brief at 165, 166, 167, citing Exh. AG-JRW at 77 & n.49, 77, 80, 83; 86 & n.59, 87-89; Attorney General Reply Brief at 46-51). Also, the Attorney General asserts that volatility of EPS growth compared to GDP growth can result in short-term differences between them that will not continue over the long-term (Attorney General Brief at 168, 169 & n.127, citing Exh. AG-JRW at 84-84, 89-90).

The Attorney General also argues that the Department should reject the Company's CAPM analysis because it relies on the forecast of only one analyst, i.e., Value Line

(Attorney General Brief at 169, citing Exh. NG-AEB-1, at 47-52). She contends that one analyst will not represent the expectations of all investors in the market and, therefore, the Company's CAPM analysis is flawed (Attorney General Brief at 169, citing Tr. 8, at 881).

(2) Empirical Capital Asset Pricing Model

The Attorney General objects to the use of the ECAPM to estimate the Company's required ROE (Attorney General Brief at 162). She asserts that (1) the ECAPM has not been theoretically or empirically validated in refereed journals and (2) Value Line and Bloomberg's adjusted betas already address the purported empirical issues with the CAPM (Attorney General Brief at 162-163, citing Exh. AG-JRW at 75).

(D) Expected Earnings Analysis

The Attorney General asserts that the Department should not rely on the expected earnings analysis because of several flaws with the approach (Attorney General Brief at 169-171). The Attorney General contends that the expected earnings approach is an accounting-based method that does not measure investor return requirements because it relies on historic book equity not the current market price of stocks (Attorney General Brief at 170, citing Exh. AG-JRW at 91). She also avers that the expected earnings approach is circular because the historic earned ROEs for the proxy companies are largely the result of regulatory forces, not market forces (Attorney General Brief at 170, citing Exh. AG-JRW at 92).

Further, the Attorney General argues that the earned ROEs of the proxy companies are not representative of National Grid's regulated utility activities because the proxy companies' ROEs include earnings from riskier business activity, such as merchant generation, construction services, and other energy services (Attorney General Brief at 171, citing Exh. AG-JRW at 92). The Attorney General also contends that National Grid's expected earnings approach is unreliable because the analysis depends on the inaccurate and strikingly overoptimistic forecasts of Value Line (Attorney General Brief at 171).

The Attorney General maintains that the sources cited by the Company as evidence that the expected earnings analysis is used to estimate ROE do not actually rely on the expected earnings analysis (Attorney General Reply Brief at 52, citing Exh. AG-JRW-Surrebuttal at 23). Moreover, the Attorney General asserts that the Federal Energy Regulatory Commission ("FERC") has rejected the use of the expected earnings analysis to estimate the cost of equity (Attorney General Reply Brief at 52).

ii. Risk and Capital Market Conditions

The Attorney General asserts that the investment risk of National Grid is a little below the average of the proxy group, as evidenced by an S&P issuer credit rating of A- compared with the proxy group average of A-/BBB+, and she claims that the Company overestimates its required ROE by assuming National Grid is riskier than the proxy group (Attorney General Brief at 147, 149, 151-152, citing Exhs. NG-AEB-1, at 3-4; AG-JRW at 9; Attorney General Reply Brief at 36, 41). She also maintains that the S&P issuer credit rating downgrade in March 2021 for National Grid from A- to BBB+ was tied to rate regulations issues with the parent company and not the investment risk of the Company (Attorney General Reply Brief at 41-42). Further, the Attorney General claims that the gas utility industry overall is among the lowest risk industries in the nation as measured by beta and, therefore, the industry's risk has declined (Attorney General Reply Brief at 53, citing Exh. JRW-6, at 3).

In addition, the Attorney General argues that National Grid's proposed PBR plan decreases the Company's financial risk relative to other companies due to the exogenous cost factor and the rate adjustments (Attorney General Brief at 151, citing Exh. AG-JRW at 8-9). Moreover, she contends that the stay-out provision of the PBR plan does not increase the Company's risk because the stay-out provision is meaningless (Attorney General Brief at 151, citing D.P.U. 10-55; D.P.U. 09-30).

The Attorney General also argues that her consultant's 7.6 percent to 9.1 percent range of reasonable ROEs and 9.0 percent ROE recommendation are supported by current capital market conditions and a trend of declining authorized ROEs for other gas companies (Attorney General Brief at 147, 172, citing Exhs. AG-JRW at 20-21, 63-64; AG-JRW-3, at 1; Attorney General Reply Brief at 37). She asserts that interest rates remain at historically low levels, which has enabled utilities to raise record amounts of capital, and that long-term expectations for inflation are just above 2.0 percent, despite expectations of increased inflation over the next five years (Attorney General Brief at 172-173, citing Exh. AG-JRW at 10-12; Attorney General Reply Brief at 37). Further, the Attorney General avers that: (1) authorized ROEs for distribution companies nationally have trended downward since 2012, coinciding with decreasing interest rates; (2) Massachusetts ROEs have trended upward while the national averages have moved downward; and (3) the differences between Massachusetts and national average ROEs have become larger in recent years (Attorney General Brief at 173-175, citing Exh. AG-JRW at 16-21).

iii. Management Performance

(A) Pipeline Safety Compliance Issues

The Attorney General contends that (1) the longstanding pipeline safety compliance issues regarding the Mid-Cape main[202] and (2) a number of recent pipeline safety enforcement actions support a finding that the Company's cavalier disregard and failure to abide by pipeline safety laws and regulations found in D.P.U. 17-170 continues (Attorney General Brief at 43, citing Exhs. DPU 7-1, Att. 1; AG 4-10, Atts. 20, 22; AG 36-1, Att. 1). Regarding the Mid-Cape main, the Attorney General contends that between 1998 and 2014, National Grid committed numerous federal and state pipeline safety violations and that, if not for these violations and the Company's poor management, the original Mid-Cape main would have remained in service for 20 to 30 more years (Attorney General Brief at 71-72, citing Exh. AG 4-10, Att. 20, 22). With respect to recent enforcement actions, the Attorney General cites to five examples.

First, the Attorney General asserts that the Company failed to meet its Compliance Work Plan Agreement goals for meter changes and proactive replacement of services, as required pursuant to Boston Gas Company, D.P.U. 16-WPA-01 (2016) ("2016 WPA") (Attorney General Brief at 44, citing Exhs. AG-RW-1, at 24; AG 4-25, Att.; AG 17-3).

---

202 The Department addresses the inclusion in rate base of costs associated with the Mid-Cape main replacement project in Section VI.B.6.c. above.

Second, the Attorney General contends that Boston Gas Company, D.P.U. 20-PL-38 (2020) addresses multiple violations of Grade 1 leak remediation and investigation requirements, which demonstrate another failure of Company management (Attorney General Brief at 45, citing Exh. AG 4-9, Atts. 1, 3). Third, the Attorney General maintains that a 2018 over-pressurization of a portion of its distribution system demonstrates management deficiency (Attorney General Brief at 46, citing Exhs. AG 1-8 & Att.; AG 4-18, Atts. 1, 3). Fourth, the Attorney General claims that National Grid's management deficiency is evidenced by the following enforcement actions by the Department regarding National Grid's LNG facilities: Boston Gas Company, D.P.U. 18-PL-32 (2019); Boston Gas Company, D.P.U. 19-PL-36 (2020); Boston Gas Company, D.P.U. 19-PL-40 (2020); Boston Gas Company, D.P.U. 19-PL-27 (2020); and Boston Gas Company, D.P.U. 19-PL-16 (2020) (Attorney General Brief at 47-48, citing Exhs. AG 4-9, Att. 2; AG 4-13, Atts. 1, 4; AG 4-16, Atts. 1, 3; AG 4-14, Att. 3; AG 4-8, Att. 24). Lastly, the Attorney General argues that National Grid's 465 Dig Safe violations demonstrate poor management (Attorney General Brief at 48-49).

(B) Distribution System Management

The Attorney General asserts that National Grid started with more cast-iron on its system than the industry average, began replacement at a slower pace, and now lags the industry by approximately 23 percent in cast-iron replacements (Attorney General Brief at 50-51). The Attorney General maintains that the Company lags the industry and a peer group of 21 similar natural gas companies in leak performance, particularly Grade 1 leaks, and asserts that the Company has a high lost and unaccounted for gas ("LAUF") average (Attorney General Brief at 52-56). The Attorney General states that the root cause of the high number of leaks is the ongoing presence of leak-prone pipe in the Company's system with 82 percent of all leaks in the system caused generally by aging infrastructure (Attorney General Brief at 53). The Attorney General also contends that the Company's LAUF has fluctuated between 2.9 percent and 4.5 percent; and she asserts that the reasonable industry target is one percent (Attorney General Brief at 56-57).

Further, the Attorney General claims that the Company's high cost per mile of replacements suggests that National Grid may not apply project planning efficiently to manage its project costs (Attorney General Brief at 59, citing Exh. AG-RW-1, at 29). She also contends that National Grid's projects routinely run over budget, by an average of 33 percent, and that the cost overruns suggest that the Company would benefit from better project-level planning (Attorney General Brief at 59-60, citing Exh. AG-RW-1, at 31).

(C) Recordkeeping

The Attorney General argues that the Company does not maintain adequate recordkeeping, which has impacted the Company's safety and reliability (Attorney General Brief at 57-58, citing Exh. AG-RW-1, at 27-30). The Attorney General cites as examples data inaccuracies relating to field data, street markings, historic installation records, and leak tracking and repair, as well as missing project data and a failure to update its procedural manuals (Attorney General Brief at 58, citing Exh. AG-RW-1, at 27-30). The Attorney General argues that contrary to the Company's assertions, she took into account the recent structural changes made by National Grid (Attorney General Reply Brief at 27, citing Exh. AG-RW-1, at 26-27, 30-31).

The Attorney General also maintains that the Company does not dispute most of the recordkeeping concerns but instead asserts that the issues will be addressed by the regulatory requirements promulgated under the Climate Act (Attorney General Brief at 58, citing Exh. NG-GSC-Rebuttal-1, at 17, 23-25). The Attorney General argues that any rulemaking required by the Climate Act is unlikely to comprehensively address the recordkeeping issues faced by National Grid (Attorney General Brief at 59). As such, the Attorney General asserts that the Department should not wait for this rulemaking to require the Company to improve its recordkeeping practices (Attorney General Brief at 58). The Attorney General also contends that PHMSA regulations already have numerous recordkeeping requirements (Attorney General Brief at 59, citing 49 C.F.R. §§ 192.13(c), 192.605(a)(3), 193.00, 193.2119).

In addition, the Attorney General maintains that the Company's recordkeeping issues have a demonstrated impact on safety and reliability (Attorney General Brief at 59). Based on these concerns, the Attorney General recommends that the Department direct the Company to develop an improved data keeping process for implementation in 2022 (Attorney General Brief at 58, citing Exh. AG-RW-1, at 47). The Attorney General also recommends that the Department set the Company's ROE at the low end of the reasonable range based on poor recordkeeping (Attorney General Reply Brief at 24).

(D) Dynamic Risk Assessment

The Attorney General maintains that the Company's response to the Dynamic Risk Report was not proportional or sufficient (Attorney General Brief at 62). The Attorney General asserts that the Company explicitly responded to only seven of the 23 general recommendations made by the Dynamic Risk Report (Attorney General Brief at 61). In addition, the Attorney General maintains that based on National Grid's ongoing problematic pipeline safety compliance, poor management of its system, and operational inefficiencies, the Company has not made changes to the core safety culture at the Company in line with the spirit of the Dynamic Risk Report (Attorney General Brief at 62; Attorney General Reply Brief at 27 n.14).

(E) Transmission Compliance Programs

The Attorney General argues that National Grid's proposed transmission compliance programs are unreasonably expensive and condensed to a timeline that is unnecessary for compliance with PHMSA, placing an undue burden on ratepayers (Attorney General Brief at 63, citing Exh. AG-RW-1, at 46). The Attorney General contends that the Company's proposal raises concerns about the Company's management and project planning (Attorney General Brief at 64). She argues that the Company should provide the Department with justification for each of the projects (Attorney General Brief at 64).

iv. Required Return on Equity

The Attorney General argues that based on the record in this proceeding the Department should reject the Company's proposed return on equity and overall cost of capital because National Grid's flawed analysis overstates the Company's required ROE (Attorney General Brief at 178; Attorney General Reply Brief at 35-36). She maintains that the Department should find that the Attorney General's 7.6-percent ROE estimate based on the CAPM and 9.1-percent ROE estimate based on the DCF establish a reasonable range of ROEs for National Grid (Attorney General Brief at 178). The Attorney General contends that the Department should set National Grid's ROE at the low end of the range, i.e., 7.6 percent, due to the Company's poor record of pipeline safety compliance and deficient management of its system (Attorney General Brief at 177-178).

b. Company

i. ROE Estimation Models

(A) Proxy Group

The Company argues that the Department should use the Company's initially proposed proxy group rather than the nine companies that the Attorney General selected (Company Brief at 243). The Company asserts that Chesapeake and NiSource do not meet the criteria necessary to ensure they are sufficiently comparable to National Grid and, therefore, should not be included in the proxy group (Company Brief at 243, citing Exhs. NG-AEB-1, at 37; DPU 19-3).

(B) Discounted Cash Flow

(1) Expected Dividend Yield

National Grid argues that the DCF model results likely underestimate the Company's required ROE under current market conditions because historically high utility stock valuations have depressed the dividend yields used in the model (Company Brief at 237, 246-247, citing Exhs. NG-AEB-1, at 25, 27; NG-AEB-Rebuttal-1, at 25-26; DPU 15-1, Atts. 12-14; Tr. 8, at 882). The Company maintains that investors predict that the utility sector will be one of the worst performing sectors in the upcoming early phase of the business cycle (Company Brief at 247, citing Exh. NG-EB-Rebuttal-1, at 20, 23). Accordingly, National Grid asserts that the DCF model's reliance on historical averages of share prices likely will understate the Company's cost of equity in the near-term (Company Brief at 247).

(2) Expected Long-Term Growth Rate

National Grid objects to the Attorney General's criticisms of the expected long-term growth rates used in their consultant's DCF analysis (Company Brief at 245-247). With respect to the purported bias in projected EPS growth rates, the Company asserts that: (1) the adoption of the 2003 Global Research Analysts Settlement ("2003 Settlement")[203] significantly reduced the bias among analysts; (2) the Attorney General draws support for the purported bias from studies that predate the 2003 Settlement; (3) the only cited study to evaluate the period after the 2003 Settlement found that in the years 2003-2006 actual earnings coincided with analysts' forecasts; and (4) the Department recently concluded that analyst growth rate forecasts are not still subject to overly-optimistic projections because of

[203] The 2003 Settlement resolved an investigation by the U.S. Securities and Exchange Commission ("SEC") and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts. D.P.U. 19-120, at 370 n.183.

the 2003 Settlement (Company Brief at 245, citing D.P.U. 19-120, at 374; Exh. NG-AEB-Rebuttal-1, at 33-35; Tr. 9, at 1050; Company Reply Brief at 73).

The Company also argues that the Attorney General's criticism of the use of growth rates from Value Line is without merit (Company Brief at 246). National Grid avers that: (1) Value Line growth rates are not systematically higher than other projected growth rates; (2) the average Value Line growth rate is lower than the average reported growth rate of Zacks; and (3) the Attorney General's consultant also relies on Value Line growth rates in his DCF analysis (Company Brief at 246, citing Exh. NG-AEB-Rebuttal-1, at 36-38).

In addition, National Grid argues that the Attorney General's DCF calculation suffers from three critical flaws (Company Brief at 243). First, National Grid alleges that over the last nine years the Attorney General's consultant has maintained a narrow bandwidth of DCF results between 8.15 percent and 9.05 percent by subjectively selecting an expected growth rate (Company Brief at 243-244, citing Exh. NG-AEB-Rebuttal-1, at 4, 44-45). The Company contends that there is a correlation of 0.88 between the dividend yield and growth rate used over the last nine years, which demonstrates that the Attorney General's consultant substitutes his own judgment for that of investors (Company Brief at 243-245, citing Exh. NG-AEB-Rebuttal-1, at 44; Company Reply Brief at 72).

Second, the Company objects to the Attorney General's 5.25-percent expected growth rate because it relies on dividend and book value per share growth rates (Company Brief at 244). National Grid asserts that dividend per share and book value per share may be directly affected by short-run management decisions and, unlike EPS growth rates, are available only from one source, which can bias the DCF calculation (Company Brief at 244). Further, the Company states that the retention growth rate is flawed because it does not include externally generated funds (Company Brief at 244, citing Exh. NG-AEB-Rebuttal-1, at 42-43; Tr. 9, at 1051-1052; RR-NG-2).

Third, the Company argues that the Attorney General's DCF analysis is flawed because of its reliance on historical growth rates, as the model is forward-looking and should, therefore, use forward-looking measures of growth (Company Brief at 244, citing Exh. NG-AEB-Rebuttal-1, at 32, 42). In addition, the Company claims that historical growth rates are likely incorporated into investors' forward-looking growth rates (Company Brief at 244, citing Exh. NG-AEB-Rebuttal-1, at 41).

(3) Exclusions

The Company avers that the exclusion of DCF results lower than seven percent is appropriate because such returns would provide a risk premium only 417 basis points above A-rated utility bonds and equity investors would consider that an insufficient return (Company Brief at 236-237, citing Exh. NG-AEB-1, at 45). National Grid claims that the exclusion of DCF results below seven percent was reasonable, and that the Attorney General's criticism of the exclusions is without merit because the Attorney General has acknowledged that the exclusions of low-end outliers did not materially impact the conclusions of the Company's consultant (Company Brief at 246).

(C) Capital Asset Pricing Models

(1) Market Risk Premium

National Grid asserts that its market risk premium is reasonable and that the Attorney General's objections to the Company's calculation of the market risk premium are without merit (Company Brief at 238, 248). The Company maintains that the forecasted EPS growth rate for the S&P 500 is a reasonable market-based estimate that has been accepted by the FERC and other utility commissions (Company Brief at 248). Further, the Company claims that a market return of 14.05 percent is reasonable because in 36 out of the past 94 years, equity returns were 14.05 percent or greater (Company Brief at 238, 249, citing Exh. NG-AEB-1, at 49-50).

In addition, the Company argues that the Attorney General's CAPM calculation is flawed because its market risk premium relies on surveys rather than forward-looking market data and does not reflect the fundamental inverse relationship between interest rates and equity risk premiums (Company Brief at 248, citing Exh. NG-AEB-Rebuttal-1, at 48, 56-59). The Company avers that the Department has found said surveys appear to be based on limited sample data and placed little weight on their results (Company Brief at 248, citing D.P.U. 19-120, at 385; D.P.U. 18-150, at 484;). Therefore, the Company asserts that the Department should continue to accord the Attorney General's CAPM results little or no weight (Company Brief at 248).

(2) Empirical Capital Asset Pricing Model

National Grid contends that the ECAPM adjusts the CAPM's tendency to under-estimate returns for companies that have low beta coefficients, such as utilities (Company Brief at 298, citing Exhs. NG-AEB-1, at 51; DPU 34-6). The Company asserts that academic studies have shown that the ECAPM significantly outperformed the traditional CAPM at predicting the observed risk premium for the various utility subgroups (Company Brief at 249, citing Exh. NG-AEB-Rebuttal-1, at 69). National Grid also maintains that the Department has placed limited weight on CAPM results and should, therefore, give at least some weight to the Company's CAPM and ECAPM results in setting the Company's ROE (Company Brief at 249, citing D.T.E. 01-56, at 113).

(D) Expected Earnings Analysis

The Company maintains that the expected earnings method is a comparable earnings analysis based on the principle of opportunity costs that calculates the earnings that an investor expects to receive on the book value of a stock (Company Brief at 238, citing Exh. NG-AEB-1, at 53). National Grid argues that it is reasonable to consider the returns that investors expect to earn on the common equity of the proxy group as a benchmark for a just and reasonable return because that is the expected earned return on equity that an investor will consider in determining whether to purchase shares in the company (Company Brief at 250, citing Exh. NG-AEB-Rebuttal-1, at 71). The Company also asserts that other state utility commissions have used the expected earnings analysis (Company Brief at 250, citing Exh. NG-AEB-1, at 53-54; Tr. 8, at 921, 925). Accordingly, National Grid contends that the Department should accord at least some weight to the expected earnings analysis (Company Brief at 250).

ii. Risk and Capital Market Conditions

The Company asserts that the proposed 10.50-percent ROE takes into account current and projected capital market conditions as well as the results of well-recognized common equity cost models (Company Brief at 233, citing Exh. NG-AEB-1, at 3, 5). National Grid contends, however, that substantial judgment is required with respect to the reasonableness of each model's limiting assumptions or methodological constraints, and no single model can be accurate under all capital market conditions at all times (Company Brief at 233-243, citing Exh. NG-AEB-1, at 7, 34, 39-40). The Company maintains that as a result, multiple methods must be considered to mitigate model bias, particularly at the present time to mitigate the impact that unprecedented Federal Reserve intervention into the financial markets is currently having on ROE estimates (Company Brief at 234, citing Exhs. NG-AEB-1, at 40; DPU 19-2).

In addition, the Company asserts that the Attorney General's assessment of National Grid's risk relative to the proxy group is false and that the Company's credit rating is now slightly lower than the proxy group because of the downgrade from A- to BBB+ (Company Brief at 251; Company Reply Brief at 71). Moreover, the Company claims that credit ratings valuate a company's ability to pay debt, not equity; that the risks and returns assumed by debt investors are far different from that assumed by equity investors; and that there is no evidence that the Company should have a lower ROE than the proxy group because of its credit rating (Company Brief at 251). Regarding the risk of the gas industry overall, the Company claims that there is no basis for the Attorney General's position as the utility sector's beta has increased significantly since the COVID-19 pandemic, from the range of 0.55 to 0.70 over the last ten years to 0.87 in this proceeding (Company Reply Brief at 75, 77, citing Exhs. AG-JRW, at 50; AG-JRW-3, at 2; NG-AEB-Rebuttal-1, at 51, 55).

The Company also provides that its recommended ROE reflects the impact of various qualitative factors (Company Brief at 239). First, National Grid asserts that the proposed stay-out period for the PBR plan increases the Company's risk because it will be unable to seek recovery of higher costs, which could prevent the Company's shareholders from realizing their ROE (Company Brief at 239, citing Exh. NG-AEB-1, at 64-65). Second, the Company contends that its recommended ROE reflects the risk imposed by the Company's high capital expenditure requirements over the next five years (Company Brief at 239, citing Exh. NG-AEB-1, at 56-57). Third, National Grid maintains that the 2017 TCJA's negative effect on the cash flow of utilities should be considered in setting the ROE (Company Brief at 240, citing Exhs. NG-AEB-1, at 29-31, DPU 19-15, Att.). Fourth, the Company argues that unique factors to operations in Massachusetts, including increased costs linked to gas safety regulations and decarbonization policies, drive up the Company's risk and should also be considered in setting National Grid's ROE (Company Brief at 240, citing Exh. NG-AEB-1, at 62-64; Tr. 8, at 879, 927-928; D.P.U. 19-120, at 405-406).

iii. Management Performance

(A) Pipeline Safety Compliance Issues

National Grid maintains that two-thirds of the notices of probable violations (“NOPVs”) cited by the Attorney General occurred before D.P.U. 17-170 and that the 22 NOPVs that the Department has issued since D.P.U. 17-170 represent a nominal fraction of the projects that the Company performs each year (Company Brief at 258). The Company also contends that the matters which were the subject of D.P.U. 20-PL-38 are similarly older and dated, occurring between 2015 and 2018 (Company Brief at 258). Moreover, National Grid asserts that it is committed to the obligations of the 2016 WPA and has worked closely with the Department to discuss the drivers of the two areas of noncompliance and updated its work plans to complete the work (Company Brief at 258-259).

The Company also contends that the Attorney General ignores record evidence demonstrating the significant improvements that the Company has implemented and effectuated since D.P.U. 17-170, including: (1) the Company’s initiatives and work efforts on gas safety and compliance, including strong progress in implementing the recommended practices of API 1173; (2) Dynamic Risk’s findings and the Company’s progress on implementation of the Dynamic Risk Report recommendations; (3) new PHMSA transmission rules that went into effect in July 2020 and were implemented by the Company; and (4) other safety and compliance initiatives that the Company has taken or will undertake to assure safe and reliable operation of the National Grid distribution system (Company Brief at 256-257; Company Reply Brief at 84).

(B) Distribution System Management

National Grid argues that the Attorney General's arguments related to leak rates and LAUF are not supported by record evidence (Company Brief at 259). The Company contends that the leak rates and LAUF for the Company are not surprising given the size and age of the system, and that the Company is addressing leak prone pipe replacement in its successful GSEP program, which the Department has approved each year since its inception (Company Brief at 259-261). National Grid also maintains that the Attorney General failed to demonstrate that her peer group comparisons are valid by not presenting the calculations or analysis used to form her opinions on the Company's performance (Company Brief at 259, citing Exhs. NG-AG 1-50; NG-AG 1-51; Tr. 13, at 1281-1282, 1286, 1292-1293, 1310-1311).

(C) Recordkeeping

National Grid asserts that the Attorney General's argument that the Company has poor management of its system ignores the record evidence of the significant improvements that the Company has implemented since its last base distribution rate case, D.P.U. 17-170 (Company Brief at 256-257, citing Exhs. NG-GSC-1, at 7-15; NG-GSC-Rebuttal-1, at 18; Company Reply Brief at 77). The Company points to its reorganization of the pipeline safety and compliance department and the oversight responsibility of that department as an organizational change that has led to improvements in executing work in a safe manner and compliance with federal and state regulatory requirements and Company policies and procedures governing field work (Company Brief at 262, citing Exh. DPU 16-1; Company

Reply Brief at 80-81, citing Exh. NG-GSC-Rebuttal-1, at 22-23). The Company contends that the Attorney General simply provides conclusions without supporting evidence (Company Reply Brief at 81).

(D) Dynamic Risk Report

National Grid contends that the Attorney General's claims regarding the Dynamic Risk Report are baseless (Company Brief at 264). Specifically, the Company asserts that it submitted a comprehensive response to the Dynamic Risk Report and identified all issues that the Company will address (Company Brief at 264). The Company also maintains that it takes seriously the recommendations in the Dynamic Risk Report and that it has developed a robust and detailed implementation plan that it is executing (Company Brief at 264, citing Exhs. NG-GSC-1, at 19-28; NG-GSC-3). National Grid maintains that in response to the Dynamic Risk Report, the Company has already completed ten action plans, has an additional three high-priority action plans that are in progress, and is continuing work on ten long-term action plans (Company Reply Brief at 81-84).

(E) Transmission Compliance Programs

The Company contends that the Attorney General's argument that the transmission compliance projects are too costly is not based in fact (Company Brief at 265). National Grid states that the Company has not yet requested recovery of those expenses and that a prudency review will take place in its next base distribution rate case (Company Brief at 265).

iv. Required Return on Equity

National Grid maintains that the Department should award the Company an ROE of 10.50 percent and reject the Attorney General's flawed ROE analysis (Company Brief at 256). The Company asserts that events since National Grid's most recent base distribution rate case suggest the Company's ROE should be increased from 9.50 percent (Company Brief at 255). National Grid claims that: (1) its pipeline safety performance has improved; (2) historically high utility stock valuations cause the DCF model to understate the required ROE; (3) the utility sector's risk, measured by beta, has increased significantly since the COVID-19 pandemic; and (4) expectations of inflation and interest rates have increased (Company Brief at 255-256, citing Exhs. NG-AEB-1, at 25, 27; NG-AEB-Rebuttal-1, at 20, 23, 25-26, 51, 55; DPU 15-1, Atts. 12-14; Tr. 8, at 882, 929-930; Tr. 9, at 1033-1036).

3. Analysis and Findings

a. ROE Estimation Models

i. Proxy Group

The use of a proxy group of companies is standard practice in setting an ROE that is comparable to returns on investments of similar risk. D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110; D.P.U. 1300, at 97. The use of a proxy group is especially relevant for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded, as is the case with National Grid (Exh. NG-AEB-1, at 35). D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110. The Department has stated that companies in the proxy group must have common stock that is publicly traded[204] and must be generally comparable in investment risk. D.P.U. 1300, at 97.

In our evaluation of the proxy groups used by the Company and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match National Grid in every detail. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group and that provides sufficient financial and operating data to discern the investment risk of National Grid relative to the proxy group. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence by parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the company. D.P.U. 10-55, at 480-482. The Department has previously found that overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group.[205]

---

[204] An important aspect of the criteria for a proxy group is that financial information is readily available for publicly traded companies.

[205] The challenge when selecting a proxy group is to narrow it sufficiently to reflect the risks faced by the company in question and, at the same time, find a large enough proxy group to bring confidence to the ultimate result by mitigating any distortion introduced by possible measurement error or vagaries in an individual company's market data. In Re Public Service Company of New Hampshire, 90 NH PUC 230, 247 (2005).

D.P.U. 10-55, at 480-482. The Department has directed parties to limit criteria to the extent necessary to develop a broader as opposed to a narrower proxy group. D.P.U. 10-114, at 299; D.P.U. 10-55, at 481-482.

In this proceeding, National Grid employed more restrictive screening criteria than the criteria found reasonable in D.P.U 17-170 (Exh. DPU 19-3). For one criterion, the Company required the proxy companies derive at least 70 percent of their total operating income from regulated operations and at least 60 percent of regulated operating income from gas, whereas in D.P.U. 17-170 the Company required the proxy companies to derive at least 60 percent of operating income from regulated natural gas utility operations (Exh. DPU 19-3). As a result, National Grid excluded NJR in this proceeding though that company had been included in the Company's proxy group in D.P.U. 17-170 (Exh. DPU 19-3).

After review of the record, given the low number of gas companies in the proxy group, we are not persuaded that it was reasonable to apply a more restrictive screening criterion in this proceeding (Exhs. NG-AEB-1, at 38; AG-JRW at 6; DPU 19-3). Furthermore, the Department recognizes that NJR fails to pass the more restrictive screen by only a small margin (Exh. NG-AEB-1, at 38). Accordingly, the Department considers the ROE results provided by the Company that included NJR.

The Company argues that the Department should use the Company's initially proposed proxy group of six companies rather than the nine companies that the Attorney General selected, including Chesapeake, NiSource, and NJR (Company Brief at 243). The Company argues that Chesapeake and NiSource should be excluded because they are not sufficiently comparable to National Grid (Company Brief at 243, citing Exhs. NG-AEB-1, at 37; DPU 19-3). We note, however, that the Company's consultant's rebuttal testimony and updated ROE analyses included all nine companies "to reduce the scope of contested issues" (Exh. NG-AEB-Rebuttal-1, at 13-14). Specifically, the consultant's rebuttal testimony: (1) applied updated market data to the same proxy companies selected by the Attorney General; (2) did not present the results of the ROE analyses using updated market data applied to its initially proposed proxy group for the Department's consideration; and (3) opined that the updated ROE analyses still supported her initial ROE recommendations (Exhs. NG-AEB-Rebuttal-1, at 13-14; AG-JRW at 21). Nevertheless, after review, with the exception of the exclusion of NJR discussed above, we find that both consultants exercised reasonable judgment to select their respective proxy groups and that they each provided sufficient information about the proxy groups to allow the Department to draw conclusions about the relative risk characteristics of the Company versus the members of the proxy groups (Exhs. NG-AEB-1, at 36; NG-AEB-8; NG-AEB-9; NG-AEB-10; AG-JRW at 21). D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept the use of the seven-company and nine-company proxy groups to assist the Department in determining the Company's fair and reasonable cost of equity.

ii. Discounted Cash Flow Analysis

(A) Expected Dividend Yield

National Grid's analysis assumes that the DCF results underestimate the Company's cost of equity for the period that its base distribution rates will be in effect (Exhs. NG-AEB-1, at 23-27; NG-AEB-Rebuttal-1, at 23-26). The Company based this assumption on: (1) market conditions leading up to and during this proceeding that purportedly depressed the proxy companies' dividend yields; and (2) an expectation that market conditions will change in the near term such that utilities will underperform the broader market and, therefore, the proxy companies' historical dividend yields will not be representative of the proxy companies' dividend yields in the future (Exhs. NG-AEB-1, at 23-27; NG-AEB-Rebuttal-1, at 23-26).

One flaw with the Company's reasoning is that it supposes that investors and market analysts have not considered this outcome in pricing the stocks of the companies in the proxy group. The Department is not inclined to agree with this position because all available information is priced into the market and we note that Moody's, a credit ratings agency, downgraded its outlook on the entire industry (Exh. NG-AEB-1, at 9). In addition, the Company's assertion that an underperformance in the utility sector could result in the DCF understating the cost of capital relies on utility stocks behaving as they have historically during the early expansion phase of the business cycle (Exh. NG-AEB-Rebuttal-1, at 4). However, the Company noted that recently utility stocks have behaved more like the overall market as compared to their historical performance as a safe-haven asset during turbulent markets (Exh. NG-AEB-1, at 8). The Company also stated that recent market volatility affected the utility sector differently than in other historical periods (Exh. NG-AEB-1, at 8). Therefore, we find that it is not reasonable to assume that the utility sector will suddenly begin behaving as it has historically during the current unsettled market while the COVID-19 pandemic continues to affect investor expectations.

As described below, the record does not support a finding that the stock prices used in the DCF analyses are not representative of what the stock prices will be when the Company's rates are in effect. Utility stock prices have been above historical levels as a result of, among other things, the Federal Reserve's accommodative monetary policies since the Great Recession[206] (Exh. NG-AEB-1, at 14, 24-26). The record also shows that investors bid up utility stock prices in this era of low interest rates (Exh. NG-AEB-Rebuttal-1, at 25). The Company's position that that these monetary policies and market conditions will not persist in the near-term rests on speculative assumptions.

For example, the Department is unable to assign probative value to the Company's assertion that "many equity analysts believe long-term interest rates will increase in 2021" because this opinion lacks foundation and is speculative (Exh. NG-AEB-Rebuttal-1, 23-24). Further, the Company's position that there will be a shift in Federal Reserve policy and a corresponding increase in interest rates is inconsistent with the Company's own testimony

---

[206] The Great Recession began in December 2007 and ended in June 2009, making it the longest recession since World War II. https://www.federalreservehistory.org/essays/great-recession-of-200709.

that "there is still uncertainty regarding the near-term effect of COVID-19 on the economy and the financial markets" (Exh. NG-AEB-Rebuttal-1, at 18). This statement on the economy and financial markets suggests that consistent with the testimony of the Attorney General's consultant, the impact of federal policy on stock prices in 2020 and 2021 may be similar in the near-term (Exhs. NG-AEB-Rebuttal-1, at 18; AG-JRW-Rebuttal at 4; Tr. 9, at 1033-1034 (expected that the Federal Reserve will pursue a "dovish" monetary policy (supporting low interest rates))).

Moreover, we find that National Grid's speculative testimony regarding the utility sector's underperformance in the early expansion phase of the business cycle does not support a finding that stock prices used in the Company's DCF analysis are not representative of current or future market conditions (Exhs. NG-AEB-Rebuttal-1, at 21-23; DPU-2). National Grid's emphasis on the utility sector's underperformance misses the point that the performance of the utility sector, as discussed in the Fidelity Investments article cited by the Company, is relative to the broader market (Exh. DPU-2, at 45). Although the returns of other sectors historically experience faster growth in the early expansion phase of the business cycle, there is not clear evidence on the record that faster growth in other sectors will result in a decline in utility stock prices; the utility sector may experience stable or relatively slower growth and still "underperform" other sectors, and historically the utility sector has "fairly persistent demand across all stages of the cycle" (Exh. DPU-2, at 45).

For the reasons set forth in this section, we do not agree with National Grid that the DCF results underestimate the Company's cost of equity because the Department finds that the proxy companies' historical dividend yields are representative. Therefore, our analysis below does not discount the DCF results for that reason.

(B) Expected Growth Rate

Determining the appropriate long-term growth expectations of investors in a DCF analysis is often difficult and controversial. D.P.U. 15-155, at 365. As discussed above, the Company and Attorney General use different growth rates in their respective DCF analyses, and each party objects to the other's choice of growth rates (Exhs. NG-AEB-5; NG-AEB-Rebuttal-1, at 30; AG-JRW at 46; AG-JRW-7, at 6). We discuss each party's objections below.

We disagree with the Attorney General that we should reject the Company's DCF results on the basis that long-term earnings growth rates of Wall Street analysts and Value Line are overly optimistic. The Department recently found that, based on the terms of the 2003 Settlement, including enforcement and structural reforms, there is a strong likelihood that the 2003 Settlement has mitigated systematic bias in overly optimistic stock recommendations. D.P.U. 19-120, at 374. In this proceeding, the studies produced by the Attorney General analyzing the period after the 2003 Settlement demonstrate that: (1) the mean forecast bias declined significantly whereas the median forecast bias essentially disappeared; and (2) analysts' forecasts generally coincided with actual earnings in the years following, with the exception of the Great Recession (Exhs. NG-AEB-Rebuttal-1, at 34-35; DPU-AG 6-1, Att. (Hovakimian & Saenyasiri (2010)), at 101-102; DPU AG 6-1, Att. (Goedhart et al (2010)), at 16; Tr. 9, at 1049-1050). Accordingly, we find there is insufficient evidence to find that long-term analysts' forecasts have systemically exceeded actual earnings since the 2003 Settlement.

The record also does not support the Attorney General's argument that National Grid's DCF analysis is flawed because Value Line growth rates were derived from a three-year base period. The Attorney General, noting that the Company corrected for an anomaly in the 2017 EPS for Northwest Natural Gas, stated that abnormally high or low figures in one of the three-year base periods could distort the growth projection (Exh. AG-JRW at 73 (emphasis added)). We find that the Attorney General's criticism rests on speculation rather than evidence; her witness did not demonstrate that the Company used any growth rates from Value Line in its calculations that were skewed upward due to anomalous single-year fluctuations in the base period (Exhs. AG-JRW at 73; AG-JRW-Surrebuttal at 13).[207] We also find the Attorney General's arguments against Value Line's projections less persuasive because her own witness used Value Line's projected growth rates in his DCF analysis (Exh. AG-JRW at 73 n.47). With respect to her observation that the EPS growth estimates of Value Line are more than 150 basis points higher than the average for Zacks and Thomson, we find that the Company relies on the forecasts of all three agencies in its analysis and that the data provided by Value Line

---

[207] The Company did make a reasonable downward adjustment to a proxy company's growth rate that was skewed upward and did not make any adjustment to a different proxy company's growth rate that was, to a lesser extent, skewed downward (Exhs. NG-AEB-5; NG-AEB-Rebuttal-1, at 38-39; AG-JRW at 73).

provides useful information to develop a range of outcomes (Exh. NG-AEB-Rebuttal-1, at 33).

Turning to the Attorney General's DCF analysis, their consultant used a 5.25-percent growth rate based on his analysis of several measures of growth for the companies in his proxy group (Exh. AG-JRW at 39). The Attorney General's consultant concluded that a 5.25-percent growth rate was appropriate based on a 3.9-percent median prospective sustainable growth rate; an average of 6.2-percent for the projected EPS, dividend per share, and book value per share growth rates; and a 5.5-percent median of Wall Street analysts projected EPS growth rates (Exh. AG-JRW at 44-46).[208]

Sustainable growth includes a measure of internal growth and a measure of external growth (Exhs. NG-AEB-Rebuttal-1, at 42; AG-JRW-Surrebuttal at 14). In support of his DCF analysis, the Attorney General's consultant testified that it was not an error to exclude a measure of external growth because: (1) internal growth is the predominant component; (2) external growth is speculative; and (3) Value Line's projected book value per share growth rates, which were included in his analysis, presumably include both measures of sustainable growth (Exh. AG-JRW-Surrebuttal at 15). We disagree. The Attorney General's calculation of the sustainable growth rate omits the external growth component of the recognized approach to calculating the sustainable growth rate (Exh. NG-AEB-Rebuttal-1, at 42). Further, the Attorney General's consultant was unable to corroborate his assertion

---

208 The Attorney General's witness explained that the median was used to control for the skew of outliers (Exh. AG-JRW at 44).

that internal and external growth are accounted for in Value Line's book value per share growth rates, and he presented no explanation for why it would be appropriate to include a separate, partial calculation of the sustainable growth rate if that measure for growth was already accounted for in his analysis (Tr. 9, at 1051-1052; RR-NG-2). Since the consultant relied on an insufficiently supported sustainable growth rate to determine the 5.25-percent growth rate used in his DCF calculation, the Department cannot rely on the Attorney General's DCF calculation of a 9.1-percent ROE in our determination of National Grid's ROE below.[209]

(C) Exclusions

In National Grid's ROE analysis, the Company excluded the DCF results for individual companies if their returns were below seven percent because "such returns would provide equity investors a risk premium only 417 basis points above A-rated utility bonds" (Exhs. NG-AEB-1, at 45; NG-AEB-5; NG-AEB-Rebuttal-3). The Department has found previously that the elimination of low-end outliers from DCF analyses without a corresponding elimination of high-end outliers skews the cost of equity upwards. D.P.U. 17-170, at 305; D.P.U. 17-05, at 708; D.P.U. 15-155, at 378.

The elimination of the low-end outliers from the Company's DCF analysis considerably reduces the sample size of the low-end cost of equity estimates and skews the

209 In light of our findings and decision regarding the Attorney General's DCF analysis, we need not address the Company's other objections to the Attorney General's DCF method in this proceeding.

low-end of the range of ROE estimates upwards from 7.50 percent to 8.24 percent (Exhs. NG-AEB-5; NG-AEB-Rebuttal-3). Therefore, the Department finds that it is more appropriate to consider presence of low- and high-end outliers in the range of DCF results from 7.50 percent to 11.81 percent in our determination of the reasonable range of ROEs for National Grid below (Exh. NG-AEB-Rebuttal-3). Further, we find this DCF analysis to be appropriate to rely upon as part of our ROE determination.

iii. Capital Asset Pricing Models

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value because of several limitations, including some questionable assumptions that underlie the model. D.P.U. 19-120, at 383; D.P.U. 17-170, at 298; D.P.U. 10-55, at 514; D.P.U. 08-35, at 207; Commonwealth Electric Company, D.P.U. 956, at 54 (1982).[210] The parties have not presented any new evidence that would serve as a basis for the Department to reevaluate our previous findings.

In this proceeding, the Attorney General asserts that the Company's expected market return includes absurd and unrealistic assumptions of future economic and earnings growth

---

[210] In D.P.U. 08-35, at 207 n.131, the Department noted the following assumptions of the CAPM: (1) capital markets are perfect with no transaction costs, taxes, or impediments to trading, all assets are perfectly marketable, and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period.

(Attorney General Brief at 150, 167, 178). The Company contends that the Attorney General's analysis is flawed because it relies on surveys rather than forward-looking market data (Company Brief at 248). In Attorney General's consultant's opinion, "one of the great mysteries in finance" is the expected return on the market, which is difficult to measure (Exh. AG-JRW at 54). While the parties present significantly different results, both consultants employed accepted approaches to estimate their respective market returns (Exhs. NG-AEB-Rebuttal, at 3; AG-JRW at 55-56; Tr. 8, at 883-884).[211]

Neither consultant, however, seems to have placed significant weight on their CAPM results in their ultimate recommendations for the cost of equity. For example, the Company's consultant testified that all three of her models were considered in her reasonable range of ROEs for the Company but provided only vague explanations in her testimony for how the models were specifically weighed in her recommendation (Exh. NG-AEB-1, at 9, 38-40, 68; Tr. 8, at 929-930). In the absence of a specific explanation for how the CAPM and ECAPM results factored into National Grid's analysis, we infer from the following observations that the Company's consultant placed little weight, if any, on the results of the CAPM and ECAPM: (1) the Company's DCF analysis and expected earnings analysis results fall within the Company's proposed reasonable range of ROEs; and (2) the

---

211 Accepted approaches to estimating the market return include using realized market returns during a historical time period; applying the DCF model to a representative market index, such as the S&P 500; and surveying academics and investment professionals (Exhs. NG-AEB-Rebuttal, at 3; AG-JRW at 55-56; Tr. 8, at 883-884). Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc., 169 FERC ¶ 61,129, at P 239 (2019).

Company's range of CAPM and ECAPM results of 11.45 percent to 12.81 percent are above the proposed reasonable range of ROEs by a significant margin (Exhs. NG-AEB-Rebuttal-2; NG-AEB-Rebuttal-3; NG-AEB-Rebuttal-4; NG-AEB-Rebuttal-5). In addition, while the Company's estimate of the market return, based on a DCF analysis of the S&P 500 may be indicative of investors' short-term expectations, the Department finds that it overstates investors' long-term expectations considering that the long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP (Exh. AG-JRW at 79-91).

The Attorney General's consultant also places little weight on his CAPM results in his recommended ROE of 9.0 percent, which is 140 basis points higher than his CAPM results (Exhs. NG-AEB-Rebuttal-1, at 48; AG-JRW at 33, 95). In the opinion of the Attorney General's consultant, "risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities" (Exh. AG-JRW at 33).

Considering the limited weight each consultant seems to place on their respective CAPM results in their ROE recommendation as well as the limitations and questionable assumptions inherent in the CAPM model, the Department places limited weight on the results of their respective CAPM estimates in determining the appropriate ROE.

iv. Expected Earnings Analysis

As discussed above, the expected earnings analysis is a form of the comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock (Exh. NG-AEB-1, at 53). The Department has generally rejected the results of the comparable earnings model for reasons that are not applicable here; this is the first base distribution rate proceeding in which a party has included the results of the expected earnings analysis as a key component of its ROE analysis. D.P.U. 10-55, at 516; D.P.U. 08-35, at 210; D.T.E. 01-56, at 116.[212]

The Company points to decisions by the Washington Utilities and Transportation Commission and the New Jersey Board of Public Utilities to support its claim that regulatory agencies rely on the expected earnings analysis (Exh. NG-AEB-1, at 53). After review, the Department finds that the Company has not demonstrated that regulatory agencies rely on the expected earnings analysis (Exhs. NG-AEB-1, at 53; DPU 15-1, Att. 33, at 28; DPU 15-1, Att. 34, at 71-73). In the Washington Utilities and Transportation Commission decision cited by National Grid, the witness used a comparable earnings approach that was considerably distinct from the Company's analysis and the commission noted that it generally does not apply material weight to the analysis (Exh. DPU 15-1, Att. 33, at 28; RR-DPU-37, Att. at 36-37). Also, the New Jersey Board of Public Utilities decision states only that the comparable earnings model is one of the models used by rate of return experts (Exh. DPU 15-1, Att. 34, at 71).

Further, while the record contains evidence that investors have access to the book value per share data used in the Company's analysis, we find that the record lacks evidence that investors rely on the expected earnings analysis to make investment decisions (Tr. 8,

---

212 In D.P.U. 19-120, an expected earnings analysis was presented as a corroborating method. D.P.U. 19-120, at 354 n.171.

at 921-922). Moreover, the expected earnings analysis, which is based on accounting returns, is insensitive to changes in investor return requirements (Exh. AG-JRW at 92). We also find it instructive that FERC recently determined that it would not rely on the expected earnings analysis to determine ROE (Exh. AG-JRW-Surrebuttal at 23; Tr. 8, at 926). Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc., 171 FERC ¶ 61,154, at P 126 (2020).

The Department finds that the Company has provided insufficient evidence to establish that the expected earnings analysis is a method used for estimating the cost of equity that is relied upon by regulatory agencies or investors. Therefore, we do not rely on National Grid's expected earnings analysis in our determination of the Company's ROE.

b. Range of Reasonableness

i. Introduction

When setting the range of reasonableness and then determining the allowed ROE, the Department is guided by the standard set forth in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope") and Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield"). The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. Hope at 603; Bluefield at 692-693. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692. Both quantitative and qualitative factors must be considered in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225.

The use of empirical analyses in this context is not an exact science. D.P.U. 17-170, at 305; D.P.U. 15-155, at 377; see also Southern Bell Telephone and Telegraph Company v. Louisiana Public Utility Commission, 239 La. 175, 225 (1960) (ascertainment of a fair return in a given case is a matter incapable of exact mathematical demonstration); United Railways & Electric Company of Baltimore v. West, 280 U.S. 234, 250 (1930) (what will constitute a fair return is not capable of exact mathematical demonstration). Conducting a model-based ROE analysis requires the analyst to make a number of subjective judgments. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

While the results of analytical models are useful, the Department must ultimately use its own judgment of the evidence to determine an appropriate ROE. We must apply to the record evidence and argument with the considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model driven exercise. D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978) ("experience has shown that, in making a determination as elusive as estimating the cost of equity capital, 'mathematical formulas and rules of thumb are obsolete'" citing A.J.G. Priest, Principles of Public Utility Regulation 196 (1969)).[213]

The Department generally agrees with National Grid that it is important to consider multiple methods to mitigate model bias and the limitations and questionable assumptions found in each model. Based on the findings above, however, the Department has determined that it cannot rely on the ROE estimates provided by the Attorney General's DCF analysis, the parties' CAPM analyses, or the expected earnings analysis in this proceeding. Accordingly, the Department will rely on the ROE estimates based on the adjustments to the Company's DCF model.

In order for the Department to consider the results of multiple models in our ROE analysis, the Department expects diligence by the parties in developing reliable ROE estimation model results. Further, in an effort to consider a broader range of CAPM analyses in future base distribution rate proceedings, the Department directs all electric and gas companies to submit a CAPM analysis that estimates the market return based on the Value Line universe of companies using Value Line's median of estimated dividend yields

---

213 As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

and estimated price appreciation potential in addition to the other ROE estimation models that, in the judgment of a party, provide a reliable estimate of the cost of equity.

The DCF model produces a potential ROE range of 7.50 percent to 11.81 percent. In the below sections, the Department discusses factors used to determine a reasonable range of ROEs applicable to National Grid within the broader range produced by the DCF model. Specifically, the Department evaluates National Grid's investment risk compared to the proxy companies and capital market conditions to determine a range of reasonable ROEs for National Grid in relation to the ROE model estimates based on the proxy companies. The Department then assesses certain qualitative factors discussed in Section XII.C.3.c below, to determine the appropriate ROE for the Company in this proceeding.

ii. Investment Risk

(A) Credit Rating

The Attorney General contends that National Grid has less investment risk than the proxy companies because its A- credit rating is above the average credit rating of the proxy companies of A-/BBB+ (Attorney General Brief at 147, 149, 151-152, citing Exh. AG-JRW at 9). Credit ratings provide investors with relevant information with respect to a company's risk level (Exh. NG-AEB-Rebuttal-1, at 74).[214] However, debt and equity securities are exposed to different risks and, therefore, require different returns (Exh. NG-AEB-Rebuttal-1,

214 Moody's long-term ratings are opinions of the relative credit risk of financial obligations (debt instruments) with an original maturity of one year or more. The ratings address the possibility that a financial obligation will not be honored (https://ratings.moodys.io/ratings).

at 74). As such, credit ratings alone do not reflect the full range of risk borne by equity investors (Exh. NG-AEB-Rebuttal-1, at 74).

In March 2021, National Grid's credit rating was downgraded to a BBB+ credit rating (Exhs. NG-AEB-Rebuttal-1, at 74; AG-JRW at 6 n.33). The Attorney General argues that the Department should ignore the credit rating downgrade because the downgrade was related to rate regulation issues with National Grid's parent company (Attorney General Reply Brief at 41-42; Exh. AG-JRW at 6 n.33). We disagree. It would be reasonable for investors to consider National Grid's credit rating downgrade in the assessment of investment risk (Exh. NG-AEB-Rebuttal-1, at 74). Therefore, we will rely on National Grid's BBB+ credit rating. We find that the Company's BBB+ credit rating is comparable to the proxy companies and suggests that the midpoint of National Grid's reasonable range of ROEs should be slightly above, but near the midpoint of the range of ROEs estimated based on the proxy companies (Exhs. NG-AEB-Rebuttal-1, at 74; AG-JRW at 6 n.33).

(B) PBR Proposal

The Company and the Attorney General debate the cause-and-effect connection between the PBR plan approved in Section IV above, and the cost of equity (Exhs. NG-AEB-1, at 64-65; AG-JRW at 8). While the Company states that the PBR plan increases its investment risk, the Attorney General asserts that the PBR plan reduces the Company's financial risk (Exhs. NG-AEB-1, at 64-65; AG-JRW at 8).

In recent years, the Department has found that a PBR plan's more timely and flexible cost recovery serves to reduce a company's risks while a stay-out provision as part of a PBR plan may increase a company's risks in meeting its financial requirements. D.P.U. 19-120, at 405-405; D.P.U. 18-150, at 494-495; D.P.U. 17-05, at 710-711. In evaluating the impact of a PBR plan on a particular company's investment risk as compared to the proxy companies' investment risks, the Department has considered the unique circumstances of each case to determine the effect, if any, on the company's ROE, including the structure of the PBR plan, length of the stay-out period, and existing rate mechanisms outside of the PBR plan for both the petitioner and the proxy group. D.P.U. 19-120, at 405-405; D.P.U. 18-150, at 494-495; D.P.U. 17-05, at 710-711.[215]

The Department has established in this Order a PBR plan specific to the Company. The PBR plan allows the Company to implement annual rate adjustments to provide revenue support for post-test year expense increases and capital investments and includes an exogenous cost provision (see Section IV.D above). In addition, the Department has allowed National Grid to make one-time filings during the PBR term to recover costs associated with post-test year non-GSEP capital additions and capital additions associated with significant LNG facilities projects (see Section IV.D.7 and Section X.D above). The Department, however, also has approved a five-year stay-out provision (see Section IV.D.5 above). Based on a balancing of the provisions of the PBR plan approved in this Order, the midpoint of

215 For example, the Department has considered the fully reconciling mechanisms a company had in place. D.P.U. 18-150, at 495. The Department also has found that the approval of a ten-year stay-put provision, which was significantly longer than recently approved stay-out provisions, increased a company's risks in meeting its financial obligations. D.P.U. 19-120, at 405.

National Grid's reasonable range of ROEs should be near the midpoint of the range of ROEs estimated based on the proxy companies.

(C) <u>Regulatory Risk</u>

The Company also contends that the uncertainty and risk associated with meeting Climate Policy objectives in Massachusetts and with gas safety and compliance requirements increase the overall risk of National Grid (Exh. NG-AEB-1, at 62-63). The Department recently found that there is uncertainty in the natural gas industry in Massachusetts driven by evolving climate policy and the regulatory effects of the Merrimack Valley incident, and that said uncertainties may influence investors' assessment of risk. D.P.U. 19-120, at 405. We reaffirm these findings. However, we find that the potential enactment of additional gas safety regulations and/or setting Climate Policy objectives that may affect the Company's costs during the stay-out period affects the Company's investment risk to a lesser degree in the context of a five-year stay-out period than it would for a ten-year stay-out period. As such, we have determined that, all else equal, National Grid's regulatory risk would suggest that the midpoint of National Grid's reasonable range of ROEs should be slightly above, but near the midpoint of the range of ROEs estimated based on the proxy companies.

(D) <u>Tax Cuts and Jobs Act of 2017</u>

The 2017 TCJA phased out bonus depreciation for utility companies and required the return of excess ADIT to ratepayers (Exh. NG-AEB-1, at 28). In addition, by lowering the corporate tax rate, the 2017 TCJA reduced tax expense and consequently the revenues of utility companies (Exh. NG-AEB-1, at 28-29). This change in revenue reduces Funds from

Operations ("FFO") metrics across the utility sector leading to weaker credit metrics and negative ratings actions for some utilities (Exhs. NG-AEB-1, at 29; NG-AEB-Rebuttal-1, at 6-7).

The Department recognizes the negative impacts of the 2017 TCJA on the utility sector. The Company, however, does not contend that the consequences are more pronounced for National Grid than for the companies in the proxy group, nor does the record contain evidence that suggests that they are more pronounced. The 2017 TCJA has been in effect for more than three years and credit rating agencies had issued advisories on the impact of the 2017 TCJA as early as January of 2018 (Exh. NG-AEB-1, at 29, n.20). This information is publicly available and widely known to investors. In the absence of evidence to the contrary, it is reasonable to conclude that investors are aware of the 2017 TCJA's impacts on utilities and have incorporated these changes in the determination of current and forecasted stock prices. Therefore, the Department finds that the financial markets have had adequate time to respond to the passage of the Act, that the impacts to the utility industry are incorporated into the stock prices and forecasts of the proxy companies, and by extension into the results of the DCF and CAPM models. Therefore, we find that the 2017 TCJA does not increase or decrease National Grid's investment risk relative to the proxy companies.

iii. Market Conditions

The Company expects market conditions to change while the base distribution rates are in effect (Exh. NG-AEB-1, at 34). Specifically, National Grid expects the utilities sector to underperform because the economy is entering the early expansion phase of the business cycle (Exh. AG-AEB-Rebutal-1, at 4). The Department addressed National Grid's arguments concerning the possibility of changes to Federal Reserve policy and the utility sector's relative underperformance in the early phase of the expansion cycle in Section XII.C.3.a.ii.(A) above. We find that there is insufficient evidence to support a finding, at this time, that capital market conditions should influence our determination of National Grid's reasonable range of ROEs in addition to the influence that already is reflected in the dividend yield and projected growth rate inputs of the DCF model.

iv. Trend in Authorized ROEs

The Attorney General argues that Massachusetts ROEs have trended upward, especially since 2012, and do not reflect the national downward trend in authorized ROEs (Attorney General Brief at 173-175, citing Exh. AG-JRW at 16-21). Under the principles of Hope and Bluefield, regulated utilities are entitled to earn a return on capital investments consistent with the returns for business of similar risk levels. The return for regulated utilities must be adequate to provide access to capital and to support credit quality, and they must result in just and reasonable rates for consumers. While ROEs granted in other jurisdictions may be indicative of general overall trends, without knowing what quantitative and qualitative factors were considered by these other regulatory agencies, the Department is unable to conclude that these ROEs of other companies are appropriate for National Grid's ROE. Moreover, the purported upward trend in ROEs granted in Massachusetts since 2012 is skewed by decisions at the start of that period, which set the authorized ROE for those companies at the low-end of the reasonable range to account for deficient management practices (Exh. AG-JRW at 19). D.P.U. 12-25, at 444; D.P.U. 11-01/D.P.U. 11-02, at 426. Therefore, in this case, the Department does not find it appropriate to rely on overall ROE trends presented by the Attorney General in setting the reasonable range of ROEs for the Company.

v. Conclusion

National Grid's consultant opined that 9.75 percent to 10.70 percent (a 95-basis point range) represented a reasonable range of ROEs for the Company, and the Attorney General's consultant opined that 7.6 percent to 9.1 percent (a 150-basis point range) represented a reasonable range of ROEs for the Company (Exhs. NG-AEB-1, at 9; NG-AEB-Rebuttal-1, at 13; AG-JRW at 95). Based on record evidence, how the risk and market forces impact National Grid in comparison to the proxy companies, and our analysis of the models presented, as all discussed above, we conclude that the midpoint of the reasonable range of ROEs should be slightly above the midpoint of the range of ROEs estimated using the DCF analysis (i.e., 7.50 percent to 11.81 percent). In our judgment, based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, including the presence of low- and high-end outliers in the range of DCF results, the Department finds that a 140-basis point range of ROEs with a midpoint slightly above the midpoint of National Grid's DCF results, i.e., 9.1 percent to 10.5 percent, is a reasonable range of ROEs for National Grid in this proceeding.

c. Qualitative Factors

i. Introduction

The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 11 (1978) ("The rate of return is not an immutable number, but rather one chosen from a range of reasonable rates and determined by the Department to appropriate under the circumstances"); Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, 305 (1971) (holding that the Department was not required to rely on any particular group of comparative figures to estimate ROE, as "[s]uch comparisons usually can be no more than general guides to be appraised by the [Department] in considering the fairness of rates. . . ."). It is both the Department's long-standing precedent and accepted regulatory practice[216] to consider qualitative factors

---

216 See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the

such as management performance and customer service in setting a fair and reasonable ROE. See, e.g., D.P.U. 09-39, at 399-400 (considered company's assistance to municipal and public safety officials to restore power to the customers of another company following a severe ice storm in setting allowed ROE); D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range). With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14. Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above-average or subpar management performance and customer service. Below the Department considers qualitative factors that may indicate whether National Grid's ROE should be set at the lower, mid, or higher end of the reasonable range identified above.

ii. Pipeline Safety Compliance

In D.P.U. 17-170, the Department set National Grid's ROE at the low end of the reasonable range based on a decades-long history of Pipeline Safety Division enforcement actions and an incident involving incorrectly programmed meters that led the Department to question how effectively National Grid was managing its assets. D.P.U. 17-170, at 310-312.

---

service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore).

The Department reduced National Grid's ROE to set reasonable rates in the circumstance where consumers are not being adequately served due to inefficiency, deficiency, or other like reasons and to send a message to National Grid's management and board that corporate irresponsibility would not be tolerated. D.P.U. 17-170, at 312, citing In re Valley Road Sewerage Company, 285 N.J. Super 202, 209-210 (App. Div. 1995); In re New England Telephone & Telegraph Company, 115 Vt. 494, 513 (1949).

The Attorney General has asserted that recent enforcement actions support a finding that National Grid has continued its disregard for Department requirements and a failure to abide by pipeline safety laws and regulations (Attorney General Brief at 41-43). Accordingly, we review the evidence to evaluate National Grid's efforts to improve its compliance with pipeline safety laws and regulations since its last base distribution rate proceeding. D.P.U. 17-90, at 290-291; D.P.U. 13-90, at 236.

The Department finds that National Grid has taken notable steps to improve pipeline safety and compliance on its distribution system (Exh. NG-GSC-1, at 7-15). National Grid has: (1) initiated the implementation of a PSMS based on the recommended practices of API 1173; (2) fully implemented use of professional engineers to design and approve gas system work in accordance with the Department's guidance; (3) made organizational changes to its pipeline safety and compliance department to ensure compliance with all codes and standards and responsiveness to Department audits and field investigations; and (4) established a compliance excellence steering committee to provide governance oversight and support (Exhs. NG-GSC-1, at 7-15; DPU 16-1).

The record also shows that National Grid failed to meet two of the 15 compliance goals provided in the 2016 WPA (Exh. AG 17-5, Att.). As evidenced by the assessment of a $1,000,000 civil penalty for these violations on June 3, 2020, the Department takes the Company's compliance with the WPA seriously (Exh. AG 17-5, Att.). However, most of the enforcement actions cited by the Attorney General concern noncompliance incidents that occurred prior to, during, or shortly after the Department's decision in D.P.U. 17-170 and, therefore, have limited relevance to whether National Grid's pipeline safety compliance issues have continued or the success of National Grid's efforts to improve its compliance with pipeline safety laws and regulations (Exhs. AG 4-8, Att. 24; AG 4-9, Atts. 1, 2, 3; AG 4-10, Att. 20, 22; AG 4-13, Atts. 1, 4; AG 4-14, Att. 3; AG 4-16, Atts. 1, 3; AG 4-18, Atts. 1, 3).[217] After review of the record evidence and arguments by the parties, we conclude that National Grid has demonstrated reasonable actions to improve its pipeline safety compliance issues since D.P.U. 17-170 and we cannot find that the cavalier disregard for Department requirements or persistent failure to abide by pipeline safety laws and regulations found in

217 The pipeline safety violations regarding the Mid-Cape main occurred between 1998 and 2014; the investigation for D.P.U. 20-PL-38 occurred in 2018, the over-pressurization of a portion of the Company's distribution system occurred in 2018; and the enforcement actions regarding National Grid's LNG facilities regarded incidents occurring between 2016 and 2018 (Exhs. AG 4-8, Att. 24; AG 4-9, Atts. 1, 2, 3; AG 4-10, Att. 20, 22; AG 4-13, Atts. 1, 4; AG 4-14, Att. 3; AG 4-16, Atts. 1, 3; AG 4-18, Atts. 1, 3).

D.P.U. 17-170 have continued. Accordingly, we will not set National Grid's ROE at the low end of the reasonable range on that basis.[218]

iii. Distribution System Management

The Attorney General argues that the Department should reduce National Grid's ROE because of poor system management, as evidenced by National Grid's rate of leak-prone pipe replacement, number of leaks, and amount of LAUF compared to the industry and a peer group of similar gas companies (Attorney General Brief at 49-57, citing Exhs. AG-RW-1, at 4-22; AG-RW-2). The Attorney General raises important concerns regarding National Grid's distribution system, and we acknowledge the magnitude of the challenge before National Grid to sufficiently reduce its leaks and LAUF. As discussed in Section V.D.1.b above, National Grid's public service obligation includes the responsibility to provide safe, reliable, and least-cost service to customers, and the activity of leak remediation is encompassed within the Company's public service obligation.

However, the Attorney General's argument diminishes the Company's efforts to address leaks and LAUF in the last decade. In 2010, the Department approved a targeted infrastructure recovery program designed by National Grid to increase the pace of leak-prone pipe replacement, reduce the leak rate, and maintain the safety and reliability of the distribution system (Exh. NG-GSC-Rebuttal-1, at 11). D.P.U. 10-55, at 145. In accordance with G.L. c. 164, § 145 ("Section 145"), the Department approved National Grid's GSEP in

218 The Department fully expects the Company to continue improving the safety of its system.

each year since 2014 (Exh. NG-GSC-Rebuttal-1, at 12). See also Section VI.B.1 above; D.P.U. 20-GREC-03, at 7-8. Since 2010, National Grid has replaced about 1,222 miles of leak-prone pipe and 12,096 services (Exh. NG-GSC-Rebuttal-1, at 12-13). Over the last ten years, National Grid's efforts to replace leak-prone pipe, reduce leaks, and maintain safe and reliable service have been in accordance with Massachusetts law and the Department's Orders.

Moreover, the Climate Act amended Section 145 to require gas companies to file a plan with the Department to address aging or leaking infrastructure, leak rates, and LAUF that include interim targets for the Department's review. Climate Act, § 87. In addition, the amendment authorizes the Department to ensure that the interim targets are met at the appropriate pace and to assess penalties against a gas company that fails to meet its interim target. Climate Act, § 87. The Company has affirmed that it will be an active participant in the Department's rulemaking and will comply with all requirements (Exh. NG-GSC-Rebuttal-1, at 15).[219] Once National Grid's plan has been approved and implemented it will further address the Company's replacement of leak-prone pipe, leak rate, and LAUF. In consideration of these factors, we do not reduce National Grid's ROE based on the Company's rate of leak-prone pipe replacement, number of leaks, and amount of LAUF.

---

[219] The Legislature requires that the Department promulgate regulations implementing a comprehensive uniform gas leak classification under G.L. c. 164, § 144(g). Climate Act, § 104.

The Attorney General also asserts that the Company's management is deficient because of a high cost per mile of replacements and project cost overruns (Attorney General Brief at 59). Except for the disallowances provided in Section VI.B.6, above, the Department has found that the costs associated with National Grid's capital additions were prudently incurred. Therefore, we do not find that Company's cost per mile of replacement or project cost variances warrant a finding of deficient management.

iv. Recordkeeping

In D.P.U. 17-170, at 238, the Department expressed concern regarding the Company's data management and specifically noted that the Company, by its own admission, relied on a less-than-adequate work and asset management system. D.P.U. 17-170, at 238. To enable the Company to remedy these issues, the Department approved a GBE plan, which was designed to implement work management, asset management, and customer enablement operating capabilities. D.P.U. 17-170, at 206, 241; D.P.U. 17-170-B at 33-38 (see also Section VIII.C.1 above). In doing so, we recognized the substantial challenges in scheduling and completing work because employees must navigate numerous, disparate, inefficient, and manual systems and processes to perform critical functions. D.P.U. 17-170, at 238. The Department also noted that the GBE program would provide necessary tools, such as data compilation and retention in relation to leak and corrosion repair work to assist the Company to accurately track, store, and report on gas operations data. D.P.U. 17-170, at 239. In this Order, we have found that the GBE program continues to be a necessary part of the Company's business and, when fully implemented, will have positive impacts on customer experience and the Company's infrastructure (see Section VIII.C.4 above).

Further, the Climate Act requires the Department to implement requirements for the maintenance, timely updating, accuracy, and security of gas company maps and records, and to incorporate these requirements as a metric in the Department's service quality indicators. Climate Act, § 86. The Company has affirmed that it will actively participate in the proceeding under the Climate Act, § 86 and will follow all requirements that are established by the Department (Exh. NG-GSC-Rebuttal-1, at 17). Once those requirements are established, they will assist in further addressing the Company's recordkeeping issues. Finally, new PHMSA rules went into effect in July 2020 and have been implemented by the Company, which should improve its recordkeeping (Exhs. NG-GSC-1, at 5; NG-GSC-Rebuttal-1, at 2). Based on these factors, the Department declines to direct the Company to develop an improved data keeping process for implementation in 2022, as suggested by the Attorney General, and declines to reduce National Grid's ROE based on recordkeeping issues.

v. Dynamic Risk Report

The Dynamic Risk Report outlined 23 recommendations, including recommendations that will take some time to implement effectively, for consideration by all gas companies, including National Grid (Exhs. NG-GSC-2, at 98-101; NG-GSC-3, at 4). The Company accepted these 23 recommendations and provided a description of its ongoing activities and action plans (Exh. NG-GSC-3, at 5-45).[220] The Dynamic Risk Report also highlighted 15 specific opportunities for improvement by National Grid, including cultural issues, barriers to completing work, over-pressure protection, and main replacement (Exhs. NG-GSC-2, at 197, 200-201; NG-GSC-3, at 48).

The Department's Pipeline Safety Division has been and continues to review all gas companies' responses to the Dynamic Risk Report, including the actions National Grid has taken and has scheduled in response to the Dynamic Risk Report. To this point, nothing in National Grid's response to the Dynamic Risk report supports an adjustment to the Company's ROE.

vi. Transmission Compliance Projects

The Attorney General's conclusions regarding the burden of National Grid's forthcoming transmission compliance projects on ratepayers are premature. The Department will evaluate the prudence of the costs associated with these projects when National Grid seeks cost recovery for these projects. While our determination on this issue could rest there, we also note that National Grid provided a reasonable explanation that its project timeline for compliance with PHMSA's new requirements builds in extra time for unforeseen circumstances (Exh. NG-GSC-Rebuttal-1, at 32).

---

220 The Dynamic Risk Report also provided recommendations that relate to state agencies, stakeholders, interested parties, and the natural gas industry in general (Exhs. NG-GSC-2, at 100-102; NG-GSC-3, at 4). While these recommendations are not directed solely at gas companies, National Grid expressed a willingness to collaborate with the Department and stakeholders to further enhance pipeline safety across the Commonwealth (Exh. NG-GSC-3, at 46).

vii. Adjustment to ROE

Based on the record evidence and the argument of the parties, the Department has found that an adjustment to National Grid's ROE is not warranted on the basis of pipeline safety compliance, distribution system management, recordkeeping, the response to the Dynamic Risk Report, or the Company's proposed transmission compliance projects. The Department, however, finds that the Company's ROE should be adjusted slightly based on the lack of continuity of management structure. While the Department has observed improvements in the Company's operations since D.P.U. 17-170, the recent history of reorganizations by National Grid USA (at least five in the last 13 years) raises concerns (Exh. DPU 53-4, Att. at 32-33, 45). As the Company's witness noted, changing organizational structures through reorganizations have advantages and disadvantages (Tr. 1, at 14). The Department finds the frequency of reorganizations over a relatively short period impacts the Company's organizational continuity and commitment of management and staff (Exh. DPU 53-4, Att. at 32-45, 83, 102-108, 115-119, 181; Tr. 1, at 14-16). This lack of continuity from frequent reorganizations causes disruptions in Company operations and periods of inefficiency, which have the potential to adversely affect customers (see Exh. DPU 53-4, Att. at 32-45, 83, 102-108, 115-119, 181). Therefore, we find a slight downward adjustment of the ROE appropriate. See D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14.

4. Conclusion

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an authorized ROE of 9.70 percent is within a reasonable range of rates that will preserve National Grid's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. In making this finding, the Department has exercised its expertise and informed judgment and has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XIII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structure are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 19-120, at 409; D.P.U. 17-170, at 313.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 19-120, at 409; D.P.U. 17-170, at 313-314.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rate should not vary significantly over a period of one or two years. D.P.U. 19-120, at 409-410; D.P.U. 17-170, at 314.

There are two parts to determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of a company's total costs to each rate class through an embedded allocated cost of service study ("ACOSS"). The allocated cost of service represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 19-120, at 410; D.P.U. 17-170, at 314.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 19-120, at 410; D.P.U. 17-170, at 315.

The results of the ACOSS are compared to revenues collected from each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 19-120, at 411; D.P.U. 17-170, at 315.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but also explicitly considers the effect of its rate structure decisions on the amount that customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goal of fairness, the Department also has ordered the establishment of special rate classes for certain low-income customers and has considered the effect of such rates and rate changes on low-income customers. D.P.U. 19-120, at 411; D.P.U. 17-170, at 316. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies – or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i) (discounted low-income rates). In addition, G.L. c. 164, § 94I ("Section 94I") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[221] The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 19-120, at 412; D.P.U. 17-170, at 316-317.

The second part of determining the rate structure is rate design. The level of the revenues generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is that a given rate class should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the

---

[221] Section 94I provides:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

Department's rate structure goals discussed above. D.P.U. 19-120, at 412; D.P.U. 17-170, at 317.

B. Marginal Cost Study

1. Introduction

For the marginal cost study, the Company uses a combination of data from Boston Gas, the former Colonial Gas, and each of their respective legacy companies (i.e., Essex Gas Company ("Essex Gas"), Lowell Gas Company, and Cape Cod Gas Company (Exh. NG-MFB-1, at 5-6).[222] The Company estimates marginal capacity-related distribution costs, which included marginal cost of capacity-related plant, marginal capacity-related operations expense, marginal capacity-related maintenance expense, and three ancillary components: marginal general plant, marginal administrative and general ("A&G") expense, and marginal materials and supplies ("M&S") expense (Exh. NG-MFB-1, at 7). Further, the Company estimates A&G expense marginal loading factors, the marginal M&S loading factor, and the marginal loading factor for general plant for several time periods in order to reflect the effect of previous mergers (Exh. NG-MFB-1, at 15-18).

[222] In 1981, the Department approved the merger of Cape Cod Gas Company and Lowell Gas Company into the new entity, Colonial Gas Company. Lowell Gas Company/Cape Cod Gas Company/Colonial Energy System, D.P.U. 514/515 (1981). In 2010, the Department approved the merger of Boston Gas and Essex Gas, with Boston Gas as the surviving entity. Boston Gas Company/Essex Gas Company, D.P.U. 09-139 (2010). In 2019, the Department approved the merger of Boston Gas and Colonial Gas, with Boston Gas as the surviving entity. D.P.U. 19-69.

The Company performs further analyses and calculations to ensure that the data used to develop the marginal cost study were appropriate and reliable (Exh. NG-MFB-1, at 8-15). In particular, the Company creates new data series to remove the effects of price inflation, differentiate distribution O&M expenses as capacity- or consumer-related, estimate normalized peak demands, and reflect the state of its distribution system (Exh. NG-MFB-1, at 8-9). The Company did not incorporate any marginal distribution capacity-related plant addition costs associated with production plant capacity in the marginal cost of capacity-related distribution plant additions because production capacity is not used in any part of its system to address low pressure during design conditions (Exh. NG-MFB-1, at 14-15). The Company's marginal cost study results in a total loss-adjusted marginal distribution cost for service for the Company of $148.47 per dekatherm ("Dth") of demand plus $0.00 per Dth of delivery quantity (Exhs. NG-MFB-1, at 19; NG-MFB-6-BOS, at 2).[223]

[223] For comparison purposes, using the same methodologies described above, the Company also conducted separate marginal cost studies for (a) Boston Gas, which results in an annual loss-adjusted marginal distribution capacity-related cost of service of $147.90 per Dth of design day demand and $0.00 per Dth of delivery quantity, and (b) Colonial Gas, which results in an annual loss-adjusted marginal distribution capacity-related cost of service of $121.66 per Dth of design day demand and $0.3983 per Dth of delivery quantity (Exhs. NG-MFB-1, at 2-3, 21-22; NG-MFB-2-BOS DIV through NG-MFB-6-BOS DIV; NG-MFB-2-COL DIV through NG-MFB-6-COL DIV).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General recommends that the Department reject the Company's proposed marginal cost study (Attorney General Brief at 197). The Attorney General claims that the Company's marginal cost study is flawed because National Grid has not demonstrated that the estimates for capacity-related distribution plant costs and maintenance expenses are reasonable (Attorney General Brief at 197).

ii. Distribution Plant Costs

The Attorney General argues that there are two main flaws with the Company's marginal cost estimates for capacity-related distribution plant (Attorney General Brief at 200). First, the Attorney General asserts that the Company's reliance on an incremental cost function rather than a total cost function results in underestimates of marginal costs and that the Company provided inadequate support for its use of an incremental cost function (Attorney General Brief at 200-201, citing Exh. AG-BWG-Surrebuttal-1, at 8–10; Tr. 6, at 713–14). Further, the Attorney General contends that it is not clear that the Company's proposed regression actually measures "the absolute level of marginal costs of distribution plant additions with respect to demand," which is the purpose of a marginal cost study (Attorney General Brief at 201, citing Exh. AG-BWG-Surrebuttal-1, at 10). The Attorney General claims the use of incremental costs does not reflect cumulative costs over any time period (Attorney General Brief at 201).

The Attorney General maintains that, although the Company's marginal cost study is similar in approach to the study approved in D.P.U. 17-170, the Department has also previously approved utilities' marginal costs studies that estimate total costs as a function of total demand (Attorney General Brief at 202, citing D.P.U. 15-80/D.P.U. 15-81, at 312–14; D.P.U. 13-75, at 336-37; D.P.U. 12-25, at 461–62; Attorney General Reply Brief at 78 n.52). Further, the Attorney General avers that the total-cost approach is consistent with two authoritative treatises (Attorney General Brief at 203, citing Exhs. AG-1; AG-2; Tr. 6, at 701-702, 719-721).[224]

Second, the Attorney General argues that certain flaws with the Company's regression for plant costs demonstrate that it does not accurately capture cost trends, thereby reducing the accuracy of the model and leading to an underestimate of marginal costs (Attorney General Brief, at 204, citing Exhs. AG-BWG-1, at 12-15, 18-21; AG-BWG-Surrebuttal-1, at 7-8, 12-13, 20-23). For example, the Attorney General asserts that the Company over-relies on dummy variables and fails to offer causal explanations for each of the dummy variables that it used in contravention of Department precedent (Attorney General Brief at 204, citing D.P.U. 10-114, at 355; Exh. AG-MFB-Surrebuttal-1, at 37-38).

In addition, the Attorney General argues that certain variables the Company uses do not accurately capture all relevant cost drivers or other important system dynamics (Attorney

---

224 Exhibits AG-1 and AG-2 are excerpts from Ramu Ramanathan, Introductory Econometrics with Applications (5th ed. 2002) and Alpha C. Chiang, Fundamental Methods of Mathematical Economics (3rd ed. 1984).

General Brief at 206-208). In particular, the Attorney General claims that the Company's plant costs model omits variables related to gas sendout, i.e., the amount of gas consumed over the course of the year, and utilizes variables that do not actually measure what they seek to measure, e.g., the use of the plastic pipe variable to capture main replacement activities (Attorney General Brief at 206-208). Consequently, she avers that the model results do not appear to provide a reasonable or reliable estimate of marginal costs, as demonstrated by the zero marginal cost estimate for the entire 1988-2009 timeframe (Attorney General Brief at 206-208). Based on these flaws, the Attorney General recommends that the Department direct the Company to provide causal justification for the inclusion of each independent variable in its next base distribution rate case and in future marginal cost studies (Attorney General Brief at 209).

The Attorney General recommends that the Department set the marginal cost of capacity-related distribution plant, with respect to demand, at $3,567 per Dth, and the marginal cost of capacity-related distribution plant, with respect to sendout, at $1.05 per Dth (Attorney General Brief at 199, citing Exh. AG-BWG-Surrebuttal-1, at 17). The Attorney General maintains that the regression used to develop her plant costs marginal cost estimate is superior to National Grid's model because it: (1) has higher predictive power than what the Company currently proposes and can account for 99.8 percent of observed variability; (2) does not require any non-causal dummy variables; (3) requires fewer variables overall; (4) includes only variables that are statistically significant; (5) does not include any autocorrelation in the residuals; (6) explicitly accounts for accelerated main replacement programs; (7) generates parameter estimates with very tight tolerances, ensuring estimate accuracy; and (8) was rigorously benchmarked against other model specifications (Attorney General Brief at 199-200, citing Exh. AG-BWG-Surrebuttal-1, at 15–16, 34 & App. A, at 14; Tr. 10, at 1139). The Attorney General also contends that her proposed regression: (1) corrects for the specification problems; (2) has better goodness of fit as measured using the R-squared value; (3) explicitly accounts for pipe replacement programs; (4) is more parsimonious; (5) lacks any non-causal dummy variables; (6) exhibits no autocorrelation in the residuals; and (7) contains only statistically significant variables (Attorney General Brief at 212, citing Exh. AG-BWG-Surrebuttal-1, at 15–16).

iii. Maintenance Expenses

The Attorney General argues that National Grid's marginal cost estimates for capacity-related distribution maintenance expenses are unreasonable because the Company over-relies on dummy variables and fails to accurately represent real trends in system size and quality, attributing explanatory power to a variable that cannot account for trends that the Company ascribes to it (Attorney General Brief at 214). With respect to the issue of dummy variables, the Attorney General maintains that, as with plant costs, the Company over-relies on dummy variables for maintenance costs in contravention of Department precedent by including four dummy variables that do not have causal explanations (Attorney General Brief at 214, 215).

The Attorney General also takes issue with the Company's model for maintenance expenses arguing that it fails to represent real trends in system size and quality (Attorney

General Brief at 215). Regarding the variable used to measure the length of cast iron pipe for the years 2005 through 2019, the Attorney General argues that National Grid has failed to provide a reasonable justification for limiting the variable to a 15-year timeframe (Attorney General Brief at 216). As a result of these flaws, the Attorney General suggests that the Company's results do not appear to provide a reasonable estimate of marginal maintenance costs (Attorney General Brief at 217). Instead, the Attorney General recommends that the Department set the marginal cost of maintenance expenses, with respect to demand, at $25.13 per Dth and set the marginal cost of capacity-related maintenance costs, with respect to sendout, at $0.23 per Dth (Attorney General Brief at 213, citing Exhs. AG-BWG-3, at 2; AG-BWG Surrebuttal-1, at 25-26).

According to the Attorney General, her proposed regression for maintenance costs provides a reasonable estimate of marginal costs that is more accurate and more precise than the model proposed by the Company because it relies on five variables: (1) dummy variable for 2018; (2) dummy variable for 2019; (3) actual peak demand; (4) total sendout; and (5) autoregressive term (Attorney General Brief at 218). The Attorney General avers that, unlike the Company's proposal, each variable used in her model has a readily interpretable explanation (Attorney General Brief at 219).

iv. Response to Company

The Attorney General argues that National Grid's arguments do not have merit and should fail because (1) the Attorney General's model is consistent with requirements for a marginal cost study in a base distribution rate case, (2) the statistical tests that National Grid references are related to a "supply plan" forecast and not to a marginal cost study in a base distribution rate case, and (3) any changes to the Attorney General's model addressing the Company's criticisms would not impact the accuracy of the Attorney General regression analysis and actually would lead to higher marginal cost estimates (Attorney General Reply Brief at 78, citing Tr. 10 at 1108, 1114, 1147–48). For the above reasons, the Attorney General recommends that the Department reject National Grid's proposed marginal cost study and direct National Grid, in its next marginal cost study, to use variables for the cumulative cost of plant additions and total demand and sendout and to provide causal justification for the inclusion of each independent variable (Attorney General Brief at 221).

b. Company

i. Introduction

The Company argues that its marginal cost study data, methodology, and results are consistent with past Department decisions related to marginal cost studies and multiple regression analyses (Company Brief at 324; Company Reply Brief at 103). Further, the Company contends that the Attorney General's proposed regression models fail the Department's directed statistical tests and suffer from omitted variable bias (Company Brief at 324; Company Reply Brief at 103). Moreover, National Grid asserts that the Attorney General's results are unreasonably high as evidence by comparing (1) the Attorney General's results to the Company's prior marginal cost studies approved by the Department and (2) the Boston Gas and Colonial Gas results to the Company's total results (Company Brief at 324-325).

ii. Distribution Plant Costs

The Company contends that both its incremental cost approach and the Attorney General's total cost approach to estimating marginal costs for plant have been previously reviewed and approved by the Department (Company Brief at 325, citing D.P.U. 17-170, at 321; D.P.U. 10-55, at 525; Company Reply Brief at 103, citing Exh. AG 9-6). Further, National Grid argues that its marginal cost study produces a stable regression analysis and addresses outliers effecting the parameters of the model by examining the model's results, adjusting the model, and retesting the model until it meets the "Best Fit" criteria (Company Reply Brief at 104, citing Exhs. NG-MFB-1 at 11-12; AG 9-6).

National Grid asserts that the Attorney General's plant model is inferior to the Company's plant model, however, because it fails two statistical tests due to an outlier at 2019 and a structural break (Company Brief at 325; Company Reply Brief at 104). Further, the Company maintains that dummy variables are necessary in certain circumstances to explain statistical relationships not captured by the model and it is important to include them, when necessary, while specific variables are used to capture cost trends (Company Brief at 326; Company Reply Brief at 104, citing Exh. NG-MFB-1 at 10, 15-16). National Grid also avers that the Company's results are in line with the results reviewed and approved in its last base distribution rate case (Company Brief at 326).

Regarding the statistical issues with the Attorney General's model, National Grid maintains that the Department has indicated in forecast and supply plan cases that these statistical flaws are critical and must be fixed when developing multiple regression analyses to be filed at the Department (Company Brief at 327). Specifically, the Company asserts that the Attorney General's statistical analysis fails the Chow Test—a test that the Department has previously directed the Company to use to test the stability of a regression model (Company Reply Brief at 104, citing Boston Gas Company/Colonial Gas Company, D.P.U. 11-09, at 39 (2012)).[225] Further, the Company argues that the Department cannot rely on witness testimony that there is a de minimis change to the estimated marginal costs after the Attorney General's model accounts for the outlier and structural break because the Attorney General did not enter a corrected model into the record (Company Brief at 326-327, citing Tr. 10, at 1114).

iii. Maintenance Expenses

As with plant costs, National Grid contends that it is important to include dummy variables when they are necessary (Company Brief at 327). National Grid asserts that mergers, acquisitions, and other structural changes over the data period justify the use of dummy variables in the Company's maintenance expense regression to explain structural shifts and or anomalous data points (Company Brief at 327). National Grid also argues that it was reasonable and appropriate to use a cast iron pipe variable for the most recent 15 years because National Grid's activities relating to cast iron pipe changed in 2005 and that the use

[225] The Chow Test is a statistical test devised by Gregory C. Chow to test the stability of estimated parameters of a regression model over the entire data range used in estimating the parameters. The Chow test is conducted by splitting the original data range in half, estimating the same equation on each subset, and determining if the coefficients from the two equations are statistically equal. D.P.U. 11-09, at iv (Glossary).

of a full 30-year data-set would not appropriately reflect current maintenance expenses (Company Brief at 327-328).

Finally, National Grid argues that the Attorney General's proposed regression for maintenance costs is not a more reasonable alternative to that of the Company (Company Brief at 328). The Company notes that, in addition to the Attorney General's not having compared the proposed results to those previously submitted and approved by the Department, the Attorney General's proposal does not account for the size and condition of the Company's distribution system and does not include necessary dummy variables (Company Brief at 328).

3. Analysis and Findings

a. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 17-170, at 319; D.P.U. 10-55, at 524; D.T.E. 03-40, at 372. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 17-170, at 320; D.P.U. 10-55, at 524; D.P.U. 07-71, at 159.

The Department has stated that a marginal cost study should: (1) include sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates; (2) use appropriate historical data that is reliable; (3) be based on proper econometric techniques to provide statistically reliable estimates; (4) be based on multi-variate regression techniques; (5) include the results of appropriate diagnostic tests to ensure the appropriateness of the regressions in the marginal cost study; and (6) not include estimates of marginal production, transmission or customer costs. D.P.U. 13-75, at 336-337; D.P.U. 12-25, at 461; D.T.E. 03-40, at 376-377.

As discussed above, the Attorney General argues that National Grid's estimates for capacity-related distribution plant costs and maintenance expenses are unreasonable and, therefore, the Department should reject the Company's proposed marginal cost study. We evaluate the Attorney General's criticisms and the Company's issues with the Attorney General's alternative marginal cost study below.

b. Incremental Cost Function vs. Total Cost Function

In this proceeding, the evidence suggests that both the incremental cost function approach and total cost function approach are valid (Exhs. NG-MFB-Rebuttal-1, at 21-22; AG-BWG-Surrebuttal-1, at 8-10; AG-1; AG-2; Tr. 6, at 719-722, 729).[226] Further, we find that National Grid's explanation for using the incremental cost function approach is reasonable (Exh. MG-MFB-Rebuttal-1, at 21-22; Tr. 6, at 729-730).

In National Grid's last two base distribution rate cases as well as the most recent gas base distribution rate case the Department adjudicated, we accepted marginal cost estimates for plant based on annual plant additions, meaning on the basis of an incremental cost

[226] While the treatises provided by the Attorney General generally support the total cost function approach, they do not support a finding that the incremental cost function approach is invalid or rebut the Company's evidence that the incremental cost function approach is valid and reasonable (Exhs. AG-1; AG-2; Tr. 6, at 719-722).

function. D.P.U. 19-120, at 426-427; D.P.U. 17-170, at 325; D.P.U. 10-55, at 525.[227] Based on the record evidence, therefore, we find that the Company's use of an incremental cost function approach was reasonable and consistent with Department precedent and we have found that the Attorney General's marginal cost study models are not sufficiently reliable for the reasons discussed below. Therefore, the Department accepts the Company's use of an incremental cost function approach in its estimate of marginal capacity-related distribution plant costs in this case. However, we direct all LDCs to address the merits of using a total cost function versus an incremental cost function when they next file a proposed marginal cost study.

c. Dummy Variables

Regarding the Attorney General's concern that the Company has over-relied on dummy variables in estimating both its distribution plant and distribution maintenance expenses, we find that the Company has demonstrated the appropriate inclusion of these variables in order to properly reflect several historical events in the Company's history such as mergers or acquisitions (Exh. NG-MFB-Rebuttal-1, at 37). In modeling, the need for dummy variables arises when individual events occur that cannot be grouped into time series (Exh. NG-MFB-1 at 10, 15-16). The Company has shown that not incorporating individual

227 We acknowledge that the Department also has accepted marginal cost studies that estimate total costs as a function of total demand, meaning on the basis of a total cost function, which is consistent with the evidence in this proceeding demonstrating that both approaches are valid. D.P.U. 15-80/D.P.U. 15-81, at 312-314; D.P.U. 13-75, at 336–337; D.P.U. 12-25, at 461–462.

events through dummy variables causes its models to fail several statistical tests (Exh. NG-MFB-Rebuttal-1, at 37-38). We, therefore, find that, as used, these dummy variables explain otherwise non-quantifiable events and do not unreasonably alter the statistical significance of the Company's analyses (Exh. NG-MFB-Rebuttal-1, at 37).

d. Cast Iron Pipe Variable

With respect to the Attorney General's argument that the Company fails to provide a reasonable justification for limiting the variable used to measure the length of cast iron pipe to a 15-year timeframe in its maintenance cost model, we find that the Company has demonstrated that, beginning in 2005, National Grid replaced cast-iron pipe at a much higher rate compared to the period prior to 2005 (Exh. NG-MFB-Rebuttal-1, at 37). It is, therefore, reasonable to include the Company's variable as proposed because it attempts to capture the condition of National Grid's distribution system (Exh. NG-MFB-Rebuttal-1, at 36).

e. Attorney General's Marginal Cost Study

As stated above, the Department has found that marginal cost studies should be based on proper econometric techniques to provide statistically reliable estimates, be based on multi-variate regression techniques, and include the results of appropriate diagnostic tests to ensure the appropriateness of the regressions in the marginal cost study. D.P.U. 13-75, at 336-337; D.P.U. 12-25, at 461; D.T.E. 03-40, at 376-377. After review, we conclude that the Attorney General's models are not sufficiently reliable because they likely suffer from omitted variable bias and are not sufficiently supported by appropriate diagnostic tests.

As an initial matter, the Attorney General's contention that Chow Tests apply only to forecast and supply plan proceedings and not marginal cost studies misses the point. At a minimum, the Department has recognized the value of conducting Chow Tests for model stability for all econometric models, which includes the econometric models used in marginal cost studies. D.P.U. 11-09, at 39 (emphasis added). In this proceeding, National Grid has provided substantial evidence demonstrating concerns with the stability of the Attorney General's model for distribution plant costs due to a structural break that the Company identified by applying the Chow Test (Exh. NG-MFB-Rebuttal-1, at 37; Tr. 6, at 730-735). When developing multiple regression models, we expect parties to address both structural shifts and outliers by conducting appropriate tests; in her proposed models, the Attorney General did not conduct Chow Tests (Tr. 10, at 1107-1108, 1111). Therefore, we find that the Attorney General failed to include the appropriate diagnostic tests in its marginal cost study.

Additionally, the Attorney General's models lack specific variables that reflect the state of the Company's distribution system in the distribution plant regression to account for main replacement activities (Exh. NG-MFB-Rebuttal-1, at 12). As a result, her models are likely to lead to the assignment of relevant costs to other events such as load increases, which would bias the results of the model (Exh. NG-MFB-Rebuttal-1, at 14-15). We find that for National Grid, which has an aging, leak-prone distribution system, the removal of this specific variable renders the Attorney General's models impractical. Further, the Attorney

General's capacity-related distribution plant model fails two statistical tests in that it has a structural break and an outlier in 2019 (Tr. 6, at 730-731; Tr. 10, at 1107, 1148).

Further, regarding the Attorney General's maintenance expense marginal cost model, we note that the primary difference between the Company's and the Attorney General's models lies in taking into consideration the size and condition of the Company's system (Exh. NG-MFB-Rebuttal-1, at 33). The Attorney General's model omits this variable and, instead, relies on a measure of total sendout (Exh. NG-MFB-Rebuttal-1, at 33). The Department agrees with the Company that in determining maintenance expenses it is important to consider the age and condition of the distribution system (Exh. NG-MFB-Rebuttal-1, at 36). It is expected that as the older cast iron pipes are replaced with modern less leak-prone infrastructure, maintenance expenses would decline (Exh. NG-MFB-Rebuttal-1, at 36). In fact, the Company has shown that beginning in 2005 when the Company began replacing cast-iron pipe at a higher rate, it observed a significant statistical relationship between feet-of-pipe replacement and maintenance expense (Exh. NG-MFB-Rebuttal-1, at 37). Moreover, when total sendout is added to the Company's maintenance expense model it fails certain statistical tests regarding the inclusion of only significant variables and the presence of autocorrelation in the residuals (Exh. NG-MFB-Rebuttal-1, at 34-35). Based on the foregoing analysis, the Department finds that the Attorney General's proposed model is less reliable than the Company's model.

f. Conclusion

Our review of the Company's proposed marginal cost study indicates that the study is consistent in methodology with previously approved studies and that it incorporates sufficient detail to allow for a full understanding of the methods used to determine the marginal cost estimates. National Grid excluded from the marginal cost study all production, transmission, and customer costs and, instead, limited its marginal cost study to capacity-related distribution costs (Exh. NG-MFB-1 at 4, 7). This method is consistent with Department precedent. D.P.U. 19-120 at 426; D.P.U. 17-170, at 323; D.T.E. 03-40, at 377.

Further, we find that National Grid used appropriate historical data that are reliable in developing a marginal cost study (Exh. NG-MFB-1, at 8-10). Similar to the approach approved in D.P.U. 17-170, the Company relied on available data for Boston Gas, Colonial Gas, and their legacy companies (Exh. NG-MFB-1, at 5-6). Further, the Company established the following rules regarding the data used: (1) each data series must be available, uninterrupted, for at least the most recent 30 years; and (2) each data series must be accurate, reliable, and measured and recorded on a reasonably consistent basis throughout the period (Exh. NG-MFB-1, at 8). Based on this data, the Company adjusted all plant addition data for inflation, separated O&M expenses into capacity- and customer-related, normalized peak demand, and developed measures to reflect the condition and use of the distribution system (Exh. NG-MFB-1, at 9). The Company also developed a number of data points to reflect major historical events over the 30-year period of the data (Exh. NG-MFB-1, at 10).

Our review of the econometric analyses performed by the National Grid to develop the marginal distribution capacity-related costs, indicates that the Company has sufficiently documented its method of estimation and has applied proven econometric techniques (Exhs. NG-MFB-2 through NG-MFB-6). The Department also finds that National Grid used multi-variate regression techniques and performed appropriate diagnostic tests to ensure the appropriateness of the regressions (Exhs. NG-MFB-2 through NG-MFB-6). Based on the foregoing, we conclude that the marginal cost study provided by National Grid is reasonable and consistent with Department precedent. Accordingly, we accept the Company's marginal costs as outlined above.

C. Allocated Cost of Service Study

1. Introduction

National Grid performed a combined ACOSS as a basis to assign or allocate the proposed combined cost of service in a manner that reflects the relative costs of providing service to all the rate classes of Boston Gas, Essex Gas, and Colonial Gas (Exh. NG-PP-1, at 18, 20-21).[228] To establish the cost responsibility of each customer class, National Grid functionalized total operating costs based on characteristics of utility operation; classified the functional cost elements as customer-, demand-, or commodity-related based on the factor of

228 The Company uses "B" to represent Boston Gas rate classes (e.g., R-3B), "C" to represent rate classes serving former Colonial Gas customers (e.g, R-3C), and "E" to represent rate classes serving former Essex Gas customers (e.g., G-41E).

utilization most closely matching cost causation; and then allocated costs to customer classes using internal and external allocation factors (Exh. NG-PP-1, at 21-22).

In past base distribution rate proceedings, National Grid allocated demand-related distribution costs based on a proportional responsibility ("PR") allocation factor (Exh. NG-PP-1, at 25).[229] In this proceeding, however, the Company proposed to allocate demand-related distribution costs using a peak-day allocation factor instead of the PR allocation factor because the peak-day allocation factor more closely reflects how National Grid plans its distribution network (Exh. NG-PP-1, at 25). National Grid developed its peak-day factor allocation method to reflect the utilization of distribution capacity by rate class on a peak day (Exhs. NG-PP-1, at 25; NG-PP-5, at 3).

2. Positions of the Parties

a. Attorney General

The Attorney General objects to the Company's use of a peak-day allocation factor and urges the Department to direct National Grid to allocate demand-related costs based on the PR method (Attorney General Brief at 183-188). The Attorney General maintains that the record demonstrates the peak demand allocation factor results in unreasonable cost allocations and that the Company has not demonstrated that the peak-day allocation factor more closely reflects cost causation than the PR method (Attorney General Brief at 184, 187).

229 The PR method calculates allocation factors based on rate class monthly volumes adjusted for "design" weather conditions (Exh. AG-SJR-1, at 6-7)

To illustrate, the Attorney General asserts that the Company allocated an unreasonably low 3.5 percent of mains costs to the G-54B rate class despite the evidence showing 3.5 percent is neither reflective of the demand G-54B rate class puts on the system during the peak month of February nor reflective of the demand the G-54B rate class puts on the system in any month of the year (Attorney General Brief at 184, citing Exhs. NG-PP-5(b) at 3, col. (M), line 1; NG-PP-Rebuttal at 7; AG-SJR-1, at 16 (Rev.); AG 3-1, Att. 1). The Attorney General avers that, based on demand during the winter months, it would be reasonable to allocate between five percent and eight percent to the G-54B rate class (Attorney General Brief at 184-186, citing Exhs. NG-PP-1, at 24-25; NG-PP-3(e), at 3, col. (b), rows 17, 31; DPU-AG 5-3, col. (o)).

The Attorney General argues that there is a fundamental flaw with the peak-day allocation method; namely, that the method ignores customer usage during all other times of the year (Attorney General Brief at 187). Further, she contends that the peak-day allocator does not consider the total throughput on the system from different classes at different time periods throughout the year or on an annual basis (Attorney General Brief at 187, citing Exh. NG-PP-3(e), at 3). Moreover, the Attorney General asserts that the use of the peak-day allocator results in an unjustified, $26 million-per-year cost shift to the residential heating class (Attorney General Brief at 184, 187, citing Exh. NG-PP-Rebuttal-1).

In the alternative, the Attorney General recommends that if the Department does not direct the Company to use a PR allocation factor for allocating demand-related costs, it should direct the Company to use a non-coincident peak factor allocation method (Attorney

General Brief at 188). The Attorney General asserts that this method would generate similar cost allocation as the PR method (Attorney General Brief at 188, citing Exh. AG-SJR-1, at 11-12 (Rev.)).

b. TEC

TEC contends that a peak-day demand allocator aligns rate design with cost causation (TEC Brief at 5). TEC asserts further that the evidence supports the Company's use of the peak-day allocation factor, since the Company's distribution investment decisions are driven by the need to maintain minimum pressures during design day peak hours (TEC Brief at 5, citing Exh. AG 11-8). TEC maintains that the PR allocation factor, which is based on each rate class's consumption throughout the year, does not reflect cost causation (TEC Reply Brief at 4).

Further, TEC argues that the Attorney General's claims about the allocation of mains costs to the G-54B rate class are erroneous because her method uses monthly consumption rather than peak-day demand (TEC Reply Brief at 5). Lastly, TEC recommends that the Department consider the use of "peak-day capacity tags" in future proceedings (TEC Reply Brief at 6).

c. Company

National Grid states that use of a peak-day allocator is appropriate for allocating demand-related costs because it more closely aligns with how the Company designs its distribution systems and incurs costs (Company Brief at 318, citing Exh. NG-PP-Rebuttal-1, at 3-4). The Company asserts that peak-day factor allocates costs for mains based on each rate class's utilization of capacity on a peak day, which is the primary driver of main costs (Company Brief at 318, citing Exh. NG-PP-Rebuttal-1, at 4). The Company maintains that the peak-day allocation factor of 3.5 percent for the G-54 B rate class is based on the principle of cost causation (Company Brief at 319).

3. Analysis and Findings

In evaluating the Company's rate design proposals, the Department considers its rate structure goals: to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 19-120, at 420; D.P.U. 17-170, at 313; D.P.U. 15-155, at 455; D.P.U. 15-80/D.P.U. 15-81, at 294. The most important principle underlying any ACOSS is that cost incurrence should follow cost causation. D.P.U. 19-120, at 413; D.P.U. 17-170, at 318-319; D.P.U. 10-114, at 75. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated, to the extent possible, based on equalized rates of return. D.P.U. 17-05-B at 81; D.T.E. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-210, at 214; see also G.L. c. 164, § 94I. A company's compliance with this policy satisfies the Department's goal of ensuring that rates are fair. D.P.U. 14-150, at 373; D.P.U. 92-210, at 214; D.P.U. 92-250, at 194; Western Massachusetts Electric Company, D.P.U. 89-255, at 103 (1990).

The record evidence demonstrates that National Grid's distribution system is designed in a manner to meet peak hour demand (Exhs. NG-PP-1, at 25; AG 11-8 ("the distribution system, including any upgrades, is designed to meet demand for the peak hour of the peak day"). Accordingly, we find that the Company has demonstrated the peak-day allocation factor more accurately reflects how National Grid incurs demand related costs than the PR allocation method. D.P.U. 19-120, at 422 (finding that a peak-day allocation method more accurately reflected how NSTAR Gas Company incurred demand-related costs compared to the PR allocation method).

The Attorney General claims that the peak-day factor (1) unreasonably allocates demand-related costs to the G-54B rate class, (2) ignores demand during other times of the year, and (3) shifts costs to the residential heating classes based on a comparison of the results of the peak-day method to the PR method (Exhs. NG-PP-5, at 3; DPU-AG 5-3). We disagree. The Attorney General cited no evidence, and we have found none in our review of the record, that supports a finding that the PR method more accurately reflects cost causation. Therefore, the record does not support a finding that the results of the PR method are more reasonable than the results of the peak-day method. Further, no evidence in the record demonstrates that the Company's distribution system is designed to meet non-coincident peak demand by rate class or to support the peak-day capacity tags method. To the extent that the application of the peak-day allocation factor shifts costs among rate classes in a manner that frustrates the goal of rate continuity, the Department applies the appropriate rate constraints to the cost of service, which are discussed in Section XIII.D.3.a.

Based on all of the above considerations, the Department finds that the use of a peak-day factor is an appropriate method to allocate demand-related costs in the ACOSS, as it accurately reflects how the Company incurs its demand-related costs. The Department has evaluated National Grid's proposed ACOSS and finds that the Company has assigned the appropriate costs to each rate class consistent with Department precedent for cost allocation. D.P.U. 19-120, at 422; D.P.U. 17-170, at 319; D.P.U. 10-55, at 535. The Department directs National Grid, in its compliance filing, to re-run its ACOSS to allocate its costs as approved in this Order.

D. Rate Design, Class Revenue Allocation, and Consolidation

1. Introduction

a. Class Revenue Allocation

National Grid's proposed base distribution revenue requirement is $896,641,158 (Exh. NG-PP-6(a) at 1 (Rev. 3)).[230] The Company employs two guiding principles to determine the proper revenue allocation. The first principle is the Department's tenet that rate class revenue requirements reflect equalized rates of return ("EROR") (Exh. NG-PP-1, at 32, citing G.L. c. 164, § 94I). The second principle is to mitigate extreme bill impacts both on rate classes and on individual customer subgroups (Exh. NG-PP-1, at 32).

National Grid's class revenue allocation employs the following steps to evaluate the impact of the proposed base distribution revenue increase to each rate class at EROR pursuant to Section 94I. First, the Company calculates $1,704,084,078 in total normalized test-year revenues for all rate classes as the sum of normalized (1) base distribution revenues, (2) LDAF revenues, (3) GAF revenues for sales customers, and (4) imputed GAF revenues

[230] The Company subsequently updated its base distribution revenue on July 28, 2021; however, an updated ACOSS and rate design exhibits were not provided.

for transportation customers (Exh. NG-PP-1, at 34-35). The Company used test-year weather-normalized billing units, multiplied by current base distribution rates to derive total normalized base distribution revenues (Exh. NG-PP-1, at 34). The Company derived normalized LDAF revenues by multiplying test-year normalized billing units by the LDAFs approved in D.P.U. 20-GAF-P5 (Exh. NG-PP-1, at 35). National Grid calculated normalized GAF revenues for sales and transportation customers by multiplying normalized test-year distribution billing units by the peak and off-peak GAFs approved in Boston Gas Company, D.P.U. 20-GAF-P5 (2020) (Exh. NG-PP-1, at 35). The Company uses the same method to calculate each rate class's total normalized test-year revenues. (Exh. NG-PP-6(b), at 1-5, lines 2-5 (Rev. 3)).

Second, the Company calculates each rate class's proposed base distribution rate increase at EROR by subtracting each rate class's normalized test-year base distribution revenues from each rate class's allocation of the proposed revenue requirement based on the results of the ACOSS (Exh. NG-PP-6(b) at 1-5, line 6 (Rev. 3)). The Company performs the same calculation for all rate classes combined, which results in a Company-wide base distribution rate increase of $192,144,870 (Exh. NG-PP-6(b) at 1-5, line 6 (Rev. 3)). Lastly, the Company provides the percent increase to total normalized test-year revenues for the entire Company and for each rate class based on the proposed increase to the base distribution revenue requirement, which is 11.28 percent for the entire Company (Exh. NG-PP-6(b) at 1, line 7 (Rev. 3)).[231]

Based on these steps, the Company determines that it cannot cap the base distribution revenue increase allocated to each rate class at ten percent of that rate class's total normalized revenue because each class would hit the maximum ten-percent increase allowed by Section 94I and the overall revenue requirement would result in a shortfall (Exh. NG-PP-1, at 32). Therefore, the Company applies the Company-wide increase of 11.28 percent to the total normalized test-year revenues for each rate class (Exhs. NG-PP-1, at 33; NG-PP-6(b) at 1-5, line 23 (Rev. 3)). To do so, the Company set a zero-percent floor so that no class would experience a decrease and then allocates the balance of the revenue deficiency to all classes that had not met the 11.28-percent cap (Exh. NG-PP-6(b)).

Next, the Company evaluates whether any of the rate classes receives an increase to its base distribution revenue requirement that exceeds 200 percent of the Company-wide increase in base distribution revenues (Exhs. NG-PP-1, at 34; NG-PP-6(b) at 1, line 22 (Rev. 3)). As the Company-wide increase to base distribution revenues was 27.27 percent, the Company applies a 54.55-percent cap to total base distribution revenues for each rate class (Exh. NG-PP-6(b) at 1, lines 25, 26 (Rev. 3)). After applying the cap, the Company reallocates $76 from the Colonial Gas Streetlighting rate class, G-17C, that exceeded the cap

231 In the Company's initial filing, the Company's proposed $898,849,319 revenue requirement represented an increase of 11.41 percent (Exh. NG-PP-1, at 32; NG-PP-6(b) at 1, line 7).

to all other rate classes in proportion to the total revenue requirement for those classes at EROR (Exh. NG-PP-6(b) at 1, lines 32, 33 (Rev. 3)). Finally, the Company designed rates for each rate class based upon the final revenue allocation and, after considering the Company's tariff consolidation plan discussed below, assigned final customer charges, demand rates, and volumetric rates (Exhs. NG-PP-7(b); NG-PP-7(c)).

b. Consolidation

In 2010, the Department approved the merger of Boston Gas and Essex Gas and approved the consolidation of Boston Gas' and Essex Gas' residential rate class tariffs. D.P.U. 10-55, at 558; Boston Gas Company/Essex Gas Company, D.P.U. 09-139 (2010). At the time of the merger, the Company did not propose to consolidate Boston Gas' and Essex Gas' C&I rate class tariffs because such consolidation would create operational and customer issues. D.P.U. 10-55, at 539. In 2017, the Company proposed to consolidate the C&I rate class tariffs for Boston Gas and the former Essex Gas; however, the Department disallowed the consolidation of the C&I rate classes because they would result in large base distribution revenue increases and large customer bill impacts. D.P.U. 17-170, at 339. Most recently, Boston Gas and Colonial Gas merged in 2019, with Boston Gas as the surviving entity. D.P.U. 19-69. Currently, National Grid has a total of 31 rate class tariffs: eight serve residential customers; 20 serve C&I customers; and three serve street lighting customers. Each rate class that has not been previously consolidated is designated using "B," "C," or "E" based on the customer's location in the former Boston Gas, Colonial Gas, and Essex Gas service territories. (respectively, "Boston Division," "Colonial Division," and "Essex Division").

In this proceeding, National Grid proposes to fully consolidate tariffs for non-heating residential and non-heating low-income residential Boston Division and Colonial Division customers; Rates R-1B and R-1C will consolidate into Rate R-1, and Rates R-2B and R-2C will consolidate into Rate R-2 (Exh. NG-PP-1 at 5 n. 2). This consolidation results in no change to the customer charge and an increase to the volumetric charge for customers taking service under Rates R-1B and R-2B, as well as an increase to the customer charge and decrease to the volumetric charge for customers taking service under Rates R-1C and R-2C:

	Boston Residential Residential Non-Heating R-1B & R-2B	Colonial Residential Residential Non-Heating R-1C & R-2C
Proposed Rates - Combined Revenue Allocation		
Customer Charge ($ / Mo.)	$ 10.00	$ 10.00
Distribution Charge - Peak ($ / Therm)	$ 0.9942	$ 0.9942
Distribution Charge - Off-Peak ($ / Therm)	$ 0.9041	$ 0.9041
Existing Rates		
Customer Charge ($ / Mo.)	$ 10.00	$ 7.00
Distribution Charge - Peak ($ / Therm)	$ 0.8098	$ 1.0825
Distribution Charge - Off-Peak ($ / Therm)	$ 0.7324	$ 0.9734

(Exh. NG-PP-7(a)).

For residential heating customers, the Company does not currently propose consolidation or full rate equalization but instead proposes to increase the customer charge for the Colonial Division to equal that of the Boston Division as a step toward full rate equalization, which, in turn, is a step toward tariff consolidation (Exhs. NG-PP-1, at 46, 47, 50, 53; NG-PP-7(a)). The Company also proposes to charge the same customer and volumetric rates for four sizes of Boston Division and Essex Division C&I rate classes (G-43B and G-43E, G-51B and G 51E, G-52B and G-52E, and G-54B and G-53E), but the tariffs for these rate classes are not consolidated under the proposal (Exh. NG-PP-1 at 41). For Colonial Division C&I rate classes G-41C and G-51C, the Company proposes customer charges that approach, but do not yet equal, those of comparable Boston Division rate classes G-41B and G-51B, respectively (Exhs. NG-PP-1, at 51, 54; NG-PP-7(a)). For Colonial Division C&I rate classes G-42C and G-52C, the Company proposes customer charges that equal those of comparable Boston Division rate classes G-42B and G-52B, respectively.[232]

Going forward, National Grid proposes to continue the move towards equalized rates in the Company's annual PBR filings (Exh. NG-PP-1, at 46). The Company intends to propose additional movement of base distribution rate charges and tariff consolidation in a future base distribution rate proceeding (Exh. NG-PP-1, at 44).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that National Grid's proposal to allocate the same percentage increase in revenues to each class, with an increase that exceeds ten percent, does not comply with the phase-in requirement of Section 94I (Attorney General Brief at 193;

---

[232] Specific equalization efforts as proposed are discussed further in the Rate-by-Rate Analysis section below.

Attorney General Reply Brief at 75). The Attorney General maintains that the Department has repeatedly confirmed that "'[t]he Section 94I-cap [] provides that no rate class shall receive a rate increase greater than ten percent'" (Attorney General Reply Brief at 74, citing D.P.U. 19-120, at 431-432; D.P.U. 17-170, at 316-317; D.P.U. 17-05, at 77; D.P.U. 14-150, at 168). She also asserts that the Company's proposal does not differentiate among the rate classes or ensure that the rate classes are gradually moved towards each class's cost of service (Attorney General Brief at 193). The Attorney General recommends that the Department limit the increase for base distribution rates effective October 1, 2021, to ten percent of total revenues or, alternatively, disallow the proposed roll-in of GSEP costs to base distribution rates (Attorney General Brief at 193). She also recommends that the Department apply its traditional regulatory policy to constrain the percentage base distribution rate increase for each class to no more than 200 percent of the system average base distribution rate increase (Attorney General Brief at 193-194).

The Attorney General contends that Section 94I should be interpreted in two parts (Attorney General Brief at 192). First, if some but not all classes would exceed the ten-percent limitation according to cost-allocation estimates, then a class's increase should not exceed ten percent of total revenues, other classes will subsidize that difference in the short term, and the Department must establish a reasonable phase-in period to bring each class's rates to the full cost of service estimate (Attorney General Brief at 192). Second, if all classes would exceed the ten-percent limitation, then the revenue increases to all classes should be limited to ten percent of total revenues and any amount beyond ten percent should be phased in over a reasonable period of time (Attorney General Brief at 192). The Attorney General maintains that such a phase-in should be designed with two goals: (1) to increase the utility's revenues to the full revenue requirement; and (2) to gradually move each class toward the full cost of service—neither of which are achieved under the Company's proposal (Attorney General Brief at 193).

b. TEC

TEC contends that the legislative intent of Section 94I was to limit rate shock by imposing a cap of ten percent on distribution rate increases, which includes increases to reconciling mechanisms (TEC Brief at 3). TEC claims that the plain language of the statute states that a rate increase must not exceed ten percent (TEC Brief at 3; TEC Reply Brief at 3). TEC argues that National Grid's proposal results in an unreasonable subsidization by C&I rate classes (TEC Brief at 3-4). TEC also argues that the cap imposed by Section 94I serves the purpose of promoting disciplined capital spending by the utilities (TEC Brief at 4; TEC Reply Brief at 3-4).

c. Company

i. Class Revenue Allocation

The Company asserts that the Legislature intended Section 94I to limit the disparity in distribution increases across rate classes and move class revenue requirements to EROR (Company Brief at 309). National Grid claims that the Legislature did not envision the transition of the recovery of a reconciling mechanism's cost into base distribution rates (Company Brief at 309, citing Exh. DPU 39-4). National Grid maintains that, in accordance with the plain and ordinary meaning of the statutory language, the statute unambiguously expresses the Legislature's intent to prevent cross-subsidies when one rate class is impacted by more than ten percent (Company Brief at 311; Company Reply Brief at 100). The Company also argues that the Legislature did not intend the ten-percent cap to apply when all rate classes are increased by more than ten percent because the Legislature did not use the word "all" (Company Brief at 311).

National Grid also argues that the intervenors' interpretations would result in illogical outcomes in contravention of the rules of statutory interpretation (Company Reply Brief at 101). The Company asserts that requiring any amount of the revenue requirement that exceeds an overall system increase cap to be phased in over time is inconsistent with the statutory requirement that the Department must phase in the elimination of cross class subsidies on a "revenue neutral basis" (Company Reply Brief at 101, citing Section 94I).

ii. Consolidation

The Company summarizes its testimony in support of National Grid's proposal to consolidate tariffs for non-heating residential and non-heating low-income residential Boston Division and Colonial Division customers and National Grid's proposed steps towards the equalization of customer charges and volumetric rates for certain rate classes, as discussed above (Company Brief at 289-290). No other party addressed the Company's proposal to consolidate tariffs. Specific arguments concerning the equalization process are addressed in the Rate-by-Rate Analysis section below.

3. Analysis and Findings

a. Class Revenue Allocation

Section 94I was enacted in 2012 as part of "An Act Relative to Competitively Priced Electricity in the Commonwealth." St. 2012 c. 209, § 20, codified at G.L. c. 164, § 94I. The statute provides that:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

In each adjudicated electric and gas base distribution rate case since the statute's enactment, the Department has evaluated the impacts of the rate class distribution revenue increases based on EROR to determine whether the impact to any classes exceeded ten percent of total normalized distribution revenues and, if so, directed the companies to reallocate the revenue increase to any rate classes above ten percent to the other rate classes. E.g., D.P.U. 19-120, at 432; D.P.U. 17-170, at 339-341; D.P.U. 13-75, at 338, 355. However, the Department has not adjudicated and therefore not applied Section 94I in a base distribution rate case where a company proposed a distribution revenue increase above ten percent for all rate classes.

As a result of the Department's decisions in this Order, the approved revenue increase for National Grid is on average below ten percent. Therefore, the novel issue raised by National Grid's proposal is moot, and it is appropriate for National Grid to cap the revenue increase for each rate class at ten percent, consistent with our prior decisions discussed above.[233] Accordingly, the Department directs National Grid in its compliance filing to apply a ten-percent cap on the total revenue increase for each rate class (inclusive of the costs recovered through reconciling mechanisms as adjusted in this Order), and then reallocate the base distribution revenues in excess of the ten-percent cap to the other rate classes to the extent they have room under the cap, as demonstrated on Schedule 10.[234]

---

233 The Department issued a briefing question for the parties to discuss the legal basis under Section 94I that supports the Company's proposal for a base distribution revenue increase that exceeds ten percent of total revenues for each rate class. D.P.U. 20-120, Hearing Officer Memorandum at 2 (May 26, 2021). Although we do not reach this legal question, the Department notes that while the Attorney General's quotation of prior Department decisions is correct, her characterization of the Department's interpretation of Section 94I in those decisions is taken out of context. Where the Department has stated previously that Section 94I provides that no rate class shall receive a rate increase greater than ten percent, it has always been: (1) in the context of evaluating whether to design rates based on class revenue requirements at EROR or to design rates based on class revenue requirements approximating EROR because of high rate class bill impacts, consistent with Section 94I; and (2) in circumstances where it was possible to reallocate class revenues increases above ten percent to rate classes experiencing a revenue requirement change below ten percent. E.g., D.P.U. 19-120, at 432; D.P.U. 17-170, at 339-341; D.P.U. 13-75, at 338, 355. The Department's prior application of Section 94I has been consistent with the Department's discretion under Section 94I to design rates that move rate classes toward EROR over a reasonable period of time. G.L. c. 164, § 94I; Meyer v. Veolia Energy North America, 482 Mass. 208, 211 (2019) ("[w]e interpret a statute according to the intent of the Legislature, which we ascertain from all the statute's words, 'construed by the ordinary and approved usage of the language' and 'considered in connection with the cause of its enactment, the mischief or imperfection to be remedied and the main object to be accomplished.'"). To clarify, however, the Department has not previously interpreted Section 94I as requiring the Department to limit a company's overall distribution rate increase to ten percent.

234 Costs for certain items adjusted in a base distribution rate case and recovered through reconciling mechanisms generally remained fixed until the next base distribution rate

Section 94I affords the Department the discretion to determine how, and over what reasonable period of time, to phase in the elimination of rate class cross subsides when the class revenue allocation of the revenue increase approved in a base distribution rate case based on EROR would impact at least one rate class by ten percent or more, provided that the elimination of class cross subsidies over time is achieved on a revenue neutral basis. G.L. c. 164, § 94I. The record in this proceeding does not support a method for phasing in the elimination of rate class cross subsidies. Accordingly, consistent with the Department's past practice and in light of the requirements of the PBR plan set forth in this Order, the Department will not require additional adjustments to base distribution rates during the term of the PBR plan to phase in the elimination of any rate class cross subsidies. Nevertheless, the Department directs all gas and electric companies to include a proposal in their future base distribution rate cases to eliminate cross subsidies over time if the increase to any one rate class based on EROR exceeds ten percent. The companies' proposals should consider factors including, but not limited to, the number and size of rate classes over ten percent, the magnitude of the class increases over ten percent, and each company's recent and projected interval of base distribution rate proceedings.

---

case (e.g., local production and storage, and gas supply acquisition costs). Consistent with Department precedent, Section 94I applies to the revenue increase for costs recovered through reconciling mechanisms that are approved in a base distribution rate case as well as the approved increase to base distribution rates. D.P.U. 14-150, at 397-398.

After review, the Department accepts the Company's proposal to cap the increase to each rate class at 200 percent of the Company-wide increase in base distribution revenues, as shown on Schedule 10. In addition, the Department previously has found it appropriate in certain cases to further allocate the approved revenue increase so that no rate class receives a rate decrease. D.P.U. 19-120, at 432, citing, D.P.U. 17-170, at 342; D.P.U. 11-01/D.P.U. 11-02, at 478; D.T.E. 01-56, at 139. As previously noted, the Department's goals of fairness and equity include ensuring that the final rates to each rate class represent or approach the cost to serve that class. In balancing these goals with our continuity rate structure goal, the Department finds it is not appropriate in this instance to require the zero percent floor, as shown on Schedule 10 of this Order.

b. Consolidation

To determine if a tariff consolidation should be allowed, the Department must consider whether it is consistent with our rate structure goals of simplicity, efficiency, continuity, fairness, and earnings stability. D.P.U. 17-05-B at 86; D.P.U. 10-55, at 556. Further, to ensure that the goals of efficiency, fairness, and earnings stability are not contravened, the Department must examine if the classes that are proposed to be consolidated have similar load characteristics. D.P.U. 17-05-B at 86; D.P.U. 10-55, at 556. The Department also must examine bill impacts at the rate class level to determine if the continuity goal is met. D.P.U. 17-05-B at 86; D.P.U. 10-55, at 556.

Consolidating rates will simplify National Grid's rate structure and, therefore, we find that it meets our simplicity rate structure goal. D.P.U. 17-05-B, at 87; D.P.U. 10-55, at 556-557. The proposed consolidation of rate class tariffs across the Companies' division territories can be seen as the continuation of a long and progressive effort by National Grid eventually to consolidate the tariffs of all its Massachusetts gas operations into a single set of tariffs. As such, further equalization of rates and tariff consolidation represents a logical continuation of the Company's reorganization efforts and would increase both administrative efficiency and customer understanding of the Company's rate structure. D.P.U. 10-55, at 557.

In determining whether it is appropriate to consolidate rate classes, the Department also must consider whether the customers served by these rate classes have similar cost patterns. D.P.U. 17-170, at 336; D.P.U. 88-135/151, at 199-200. The Department's current ratemaking preference is to set prices based on embedded costs to encourage energy efficiency.[235] D.P.U. 17-170, at 337; D.P.U. 17-05-B, at 88; D.P.U. 15-155, at 473-490. Therefore, in any proposal to consolidate rate class tariffs, the Department will compare unit embedded costs among various existing rate classes to determine whether a rate consolidation would result in unfair inter-class subsidies. D.P.U. 17-170, at 337; D.P.U. 17-05-B, at 88.

---

[235] In the past, the Department relied on marginal cost pricing to set rates. Accordingly, the Department has previously allowed rate classes to be consolidated when unit embedded and marginal costs did not differ significantly among individual rate classes. D.P.U. 88-135/151, at 200; Cambridge Electric Light Company, D.P.U. 87-221-A at 125 (1988); D.P.U. 86-27-A at 72-73; New England Telephone and Telegraph Company, D.P.U. 1731-C at 22-25 (1987); D.P.U. 85-266-A/85-271-A at 236.

National Grid currently has eight residential rate classes and proposes to consolidate the four non-heating classes (R-1B, R-1C, R-2B, and R-2C) into two classes, Rates R-1 (R-1B with R-1C) and R-2 (R-2B with R-2C). When comparing embedded costs from the combined ACOSS and stand-alone ACOSS to serve customers in each territory, the results are as follows:

Unit Embedded Costs to serve residential non-heating customers ($/Therm)				
Consolidated	Boston Gas per stand-alone ACOSS	Boston Gas per combined ACOSS	Colonial Gas per stand-alone ACOSS	Colonial Gas per combined ACOSS
$2.0443	$2.0799	$1.9687	$2.4351	$3.0382

(Exh. DPU 17-3, Att.).

The Department is concerned with the difference in unit embedded costs between the combined Colonial Gas residential non-heating rate classes and the consolidated residential non-heating rate classes. Comparing Colonial Gas' stand-alone unit embedded costs to the consolidated residential rate classes lessens our concern, however, because the unit embedded cost of serving Colonial Gas customers is higher than that of other customers, consolidation would lead to the subsidization of Colonial Gas customers at the expense of the remaining residential non-heating customers. Nonetheless, Colonial Gas's residential non-heating consumption represents only 7.4 percent of total residential non-heating load

(Exh. NG-PP-6(b) at 10, 12 (Rev 3)).[236] Therefore, the Department finds that any subsidization would be minimal and that the consolidation of these rate classes does not contravene the Department's rate structure goals (Exh. DPU 17-3, Att.).

In addition to the unit embedded cost comparison, the Department must also consider the differences in load characteristics as well as the bill impacts that would be experienced by consolidating and equalizing these rates. The availability clauses for Rates R-1B and R-1C as well as for R-2B and R-2C are substantially identical, differentiated only by the customer location (Exh. NG-PP-10, proposed M.D.P.U. Nos. 27, 28). As such, this substantial identity of availability clauses, or condition for rate qualification, satisfies the Department's concern regarding load characteristics.

Finally, the bill impacts for non-space heating customers resulting from consolidation are within a reasonable range when weighed against our rate structure goals of simplicity and efficiency. D.P.U. 17-170, at 338-339; D.P.U. 17-05-B at 91; D.P.U. 10-55, at 558. Therefore, the Department finds the variance in bill impacts resulting from class consolidation acceptable in this instance. For all the reasons explained above, the Department approves the Company's proposal to consolidate its non-heating residential and non-heating low-income customer tariffs; the four non-heating classes (R-1B, R-1C, R-2B, and R-2C) into two classes, Rates R-1 (R-1B with R-1C) and R-2 (R-2B with R-2C).

---

236 The calculation is: 1,013,003 therms for Colonial Gas / (1,013,003 therms for Colonial Gas + 12,736,012 therms for Boston Gas) = 7.4 percent (Exh. NG-PP-6(b) at 10, 12 (Rev 3)).

The Company has not submitted a formal proposal with an overall rate equalization goal; rather the Company proposes to work towards rate consolidation (Exh. NG-PP-1, at 43). An early step in this process is to move toward equalized rates among rate classes providing service to customers similar characteristics in its division territories. The Department finds the Company's approach and considerations with respect to the steps that it needs to take to further its consolidation efforts reasonable (Exh. NG-PP-1, at 38-45). D.P.U. 17-05-B at 87-97; D.P.U. 10-55, at 556-557. Specific proposals in the current rate classes regarding rates resulting from the equalization process are addressed in the Rate-by-Rate Analysis section below. Further, the Department finds it reasonable for the Company to continue to move towards rate equalization in the PBR compliance filings.

E. Rate-by-Rate Analysis

1. Introduction

The Department must determine, for each rate class, the proper level at which to set the customer charge and distribution charges, based on a balancing of our rate design goals. For this balancing, we review the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes.

In balancing our rate design goals, the Department seeks optimal economic efficiency. Overall, the Department seeks to achieve revenue adequacy and fair apportionment of costs while promoting economically justified use. However, there are factors and constraints that affect achieving an efficient balancing of our rate design goals. In establishing specific rate structures, the Department executes its assigned ratemaking function by applying our expertise and judgment in balancing the rate design goals in consideration of public policy requirements. The rate design for each rate class is discussed below.

2. Residential

a. Rates R-1 (Residential Non-Heating) and R-2 (Low-Income Non-Heating)

i. Introduction

The Company proposes a consolidated Rate R-1 available to residential customers who do not have gas space heating equipment (Exh. NG-PP-10, proposed M.D.P.U. No. 27). Rate R-1 is proposed to be available for gas supplied through one meter for all residential non-heating appliances used in common by the tenants of a single building that contains not more than four dwelling units (Exh. NG-PP-10, proposed M.D.P.U. No. 27). This proposed rate excludes institutions, hotels, apartments, condominiums, and rooming houses in which the individual tenants are not billed separately (Exh. NG-PP-10, proposed M.D.P.U. No. 27). The Company's proposed Rate R-2 is a subsidized rate that is available to Rate R-1 eligible customers who receive any means-tested public benefit program or are eligible for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. NG-PP-10, proposed M.D.P.U. No. 28). Customers taking service on proposed Rate R-2 receive a 25-percent discount off the total bill that they would have received if taking service on Rate R-1.

The Company's current R-1B and R-2B customer charge is $10.00 per month, and R-1C and R-2C customer charge is $7.00 per month (Exh. NG-PP-1, at 47-48). The

Company's customer charge for proposed Rates R-1 and R-2 is \$10.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. Nos. 27, 28). This level represents no change to current Rates R-1B and R-2B customers and an increase of \$3.00 per month for current Rates R-1C and R-2C customers (Exh. NG-PP-7(a)). The existing volumetric charges for Rates R-1B and R-2B customers are \$0.8098 per therm during peak months and \$0.7324 per therm during off-peak months (Exh. NG-PP-7(a)).[237] The existing volumetric charges for Rates R-1C and R-2C customers are \$1.0825 per therm during peak months and \$0.9734 per therm during off-peak months (Exh. NG-PP-7(a)).

With its proposed customer charge of \$10.00, the Company proposes to collect the remaining class revenue requirement through volumetric rates of \$0.9942 per therm during peak months and \$0.9041 per therm during off-peak per months for proposed Rates R-1 and R-2 (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. Nos. 27, 28). This level represents an increase in volumetric rates for Boston Division customers and a decrease in volumetric rates for Colonial Division customers (Exh. NG-PP-7(a)).

The Company states that the proposed equalized rates send appropriate price signals because they represent the combined cost to serve both the Boston Division and the Colonial Division residential non-heating customers on a fully integrated and combined basis (Exh. NG-PP-Rebuttal-1, at 10). The Company notes that the proposed increase aligns with

---

[237] The Company's Peak Season is the winter heating season of November 1 through April 30; the Company's Off-Peak Season is the summer season of May 1 through October 31. Boston Gas, Cost of Gas Adjustment Clause, currently M.D.P.U. No. 2.3, § 6.05 (Definitions).

the results of the ACOSS as the per-unit proposed customer charge is lower than that from the ACOSS (Exh. NG-PP-Rebuttal-1, at 10).

ii. Positions of the Parties

(A) Attorney General

The Attorney General requests that the Department limit the Company's proposed increase to the customer charge for Colonial Division non-heating residential customers to no more than $2.00 per month, thereby increasing the current charge to no more than $9.00 per month (Attorney General Brief at 178, citing Exhs. AG-SJR-1 at 23 (Rev.); AG-SJR-7 (Rev.)). The Attorney General asserts that it is inappropriate to increase the customer charge and reduce the volumetric charge, as doing so can send the wrong message to customers and decrease the amount of control that customers have over the cost of their bills (Attorney General Brief at 195, citing Exh. AG-SJR-1 at 22-23 (Rev.)). The Attorney General claims that the Company's proposed change also runs the risk of having dramatically different impacts on customers at different consumption levels (Attorney General Brief at 194-195, citing Exh. AG-SJR-1, at 22-23 (Rev.)).

The Attorney General maintains that, when designing rates, it is important to evaluate the impacts on customers with differing amounts of usage because low-use customers can experience larger impacts than high-use customers when customer charges are increased (Attorney General Brief at 182). The Attorney General also argues that the Department should be sensitive to the cost of serving each customer class; the goals of efficiency and simplicity; the importance of ensuring the continuity of rates, fairness between rate classes, and corporate earnings stability; and the rate design's impacts on customers with different usage levels within customer classes, within the context of the overall revenue increase to the class (Attorney General Brief at 182-183).

(B) Company

The Company summarizes its approach to assigning customer charges to all rate classes (Company Brief at 305). Specifically, National Grid states that it designed proposed customer charges by reviewing each rate class's customer charge in relation to the ACOSS unit cost and that current customer charges are between eight percent and 71 percent of the customer related unit costs calculated from the ACOSS (Company Brief at 305, citing Exh. NG-PP-1, at 50). The Company asserts that it is appropriate to move customer charges closer to their actual customer-related per-unit costs determined in the ACOSS to reduce intra-class rate inequities (Company Brief at 305).

iii. Analysis and Findings

The Department approved the Company's consolidation of residential non-heating rates above in Section XIII.D.3.b. According to the Company's ACOSS, the existing embedded customer charge for Rates R-1B and R-2B is $21.84 per month and for Rates R-1C and R-2C is $35.62 per month (Exh. NG-PP-4(a)). When calculated together, the proposed consolidated Rates R-1 and R-2 have an embedded customer charge of $22.82 per month (Exh. NG-PP-4(a)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for Rates R-1 and R-2 best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rates for Rates R-1 and R-2 to recover the remaining class revenue requirement approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.[238]

b. Rate R-3B (Residential Heating) and R-4B (Low Income Heating)

i. Introduction

Rate R-3B is available to residential customers located in the Boston Division who have gas space-heating equipment (Exh. NG-PP-10, proposed M.D.P.U. No. 29).
Rate R-3B is available for gas supplied through one meter for all residential appliances used in common by the tenants of a single building that contains not more than four dwelling units, provided gas is the primary space-heating fuel (Exh. NG-PP-10, proposed M.D.P.U. No. 29). This rate excludes institutions, hotels, apartments, condominiums, and rooming houses in which the individual tenants are not billed separately (Exh. NG-PP-10, proposed M.D.P.U. No. 29). Rate R-4B is a subsidized rate that is available to residential customers located in the Boston Division who are eligible for Rate R-3 and receive any means-tested public benefit program or are eligible for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. NG-PP-10, proposed M.D.P.U.

[238] The calculation of all volumetric per therm delivery charges for all rates shall be truncated after the fourth decimal place.

No. 31). Customers taking service on Rate R-4B receive a 25-percent discount off the total bill that they would have received if taking service on Rate R-3B (Exh. NG-PP-10, proposed M.D.P.U. No. 31).

The Company's current and proposed Rates R-3B and R-4B customer charge is $12.00 per month (Exhs. NG-PP-1, at 47; NG-PP-7(a); NG-PP-10, proposed M.D.P.U. Nos. 29, 31). The Company proposes to collect the remaining class revenue requirement through rates of $0.7640 per therm during peak months and $0.3774 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. Nos. 29, 31). These levels represent an increase relative to the current rates of $0.6155 per therm during peak months and $0.3042 per therm during off-peak months (Exh. NG-PP-7(a)). No intervenor commented on the Company's proposal on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rates R-3B and R-4B is $30.72 per month (Exhs. NG-PP-1, at 47; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $12.00 for Rates R-3B and R-4B best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rate for Rates R-3B and R-4B to recover the remaining class revenue requirement approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

c. Rate R-3C (Residential Heating) and R-4C (Low Income Heating)

i. Introduction

Rate R-3C is available to residential customers located in the Colonial Division who have gas space-heating equipment (Exh. NG-PP-10, proposed M.D.P.U. No. 30). Rate R-3C is available for gas supplied through one meter for all residential appliances used in common by the tenants of a single building that contains not more than four dwelling units, provided gas is the primary space-heating fuel (Exh. NG-PP-10, proposed M.D.P.U. No. 30). This rate excludes institutions, hotels, apartments, condominiums, and rooming houses in which the individual tenants are not billed separately (Exh. NG-PP-10, proposed M.D.P.U. No. 30). Rate R-4C is a subsidized rate that is available to customers eligible for Rate R-3C and who receive any means-tested public benefit program or are eligible for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. NG-PP-10, proposed M.D.P.U. No. 32). Customers taking service on Rate R-4C receive a 25-percent discount off the total bill that they would have received if taking service on Rate R-3C (Exh. NG-PP-10, proposed M.D.P.U. No. 32).

The Company's current Rates R-3C and R-4C customer charge is $10.00 per month, and the Company proposes to increase the customer charge to $12.00 per month (Exhs. NG-PP-1, at 47; NG-PP-7(a); NG-PP-10, proposed M.D.P.U. Nos. 30, 32). The Company proposes to collect the remaining class revenue requirement through rates of $0.5818 per therm during peak months and $0.4469 per therm during off-peak months

(Exh. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. Nos. 30, 32). These levels represent an increase relative to the current rates of $0.4905 per therm during peak months and $0.3769 per therm during off-peak months (Exh. NG-PP-7(a)). No intervenor commented on the Company's proposal on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rates R-3C and R-4C is $37.38 per month (Exh. NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $12.00 for Rates R-3C and R-4C best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rate for Rates R-3C and R-4C to recover the remaining class revenue requirement approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

3. C&I Rate G-41 (Low Load Factor General Service Rate – Small)

a. Introduction

The Company proposes Rates G-41B, G-41C, and G-41E to serve certain small commercial and industrial ("C&I") customers in the Boston Division, Colonial Division, and Essex Division, respectively. As discussed in Section XIII.D above, the Company proposes to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of the division territory that they are served on. For the Rate G-41 classes, the Company proposes to increase the customer charge for Rate G-41C to approach but not yet equal that of G-41B and G-41E (Exh. NG-PP-7(a)). The Company proposes increases to all volumetric G-41 rates, in amounts that vary by division territory.

Rate G-41B is available to C&I customers located in the Boston Division whose metered use in the most recent peak season is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is less than or equal to 500 cubic feet per hour ("CfH") (Exh. NG-PP-10, proposed M.D.P.U. No. 33). The Company's current and proposed customer charge is $26.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 33). The Company proposes to collect the remaining class revenue requirement through rates of $0.5593 per therm during peak months and $0.4533 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 33).

Rate G-41C is available to C&I customers located in the Colonial Division whose metered use in the most recent peak period is greater than or equal to 72 percent of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is 20,000 therms (billing units) or less (Exh. NG-PP-10, proposed M.D.P.U. No. 34). The Company proposes to increase the monthly customer charge for Rate G-41C from $13.00 per month to $19.00 per month and to collect the remaining class revenue requirement through rates of $0.4638 per therm during peak months and $0.3774 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 34).

Rate G-41E is available to C&I customers located in the Essex Division whose metered use in the most recent peak season is greater than or equal to 73 percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is 22,000 therms or less (Exh. NG-PP-10, proposed M.D.P.U. No. 35). The Company's current and proposed customer charge is $26.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 35). The Company proposes to collect the remaining class revenue requirement through rates of $0.5115 per therm during peak months and $0.4191 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 35).

b. Positions of the Parties

i. Attorney General

The Attorney General recommends that the Department approve rates for small C&I customers that (1) gradually equalize rates for the Boston Division and the Colonial Division and (2) do not impose unreasonably large bill increases to any customer (Attorney General Brief at 196, citing Exh. AG-SJR-1, at 28 (Rev.)). The Attorney General claims that the Company has not adequately demonstrated that an increase in the Colonial Division's customer charges for G-41C customers of $6.00 is reasonable (Attorney General Brief at 196). Further, the Attorney General contends that the Company's proposed volumetric charges demonstrate an increase in the difference between volumetric rates for customers in the Boston Division with those in the Colonial Division from less than four cents to more than nine cents per therm (Attorney General Brief at 196, citing Exh. AG-SJR-1, at 27 (Rev.); proposed M.D.P.U. No. 34, at 1; proposed M.D.P.U. No. 44, at 1).

The Attorney General recommends that National Grid move both the customer and volumetric charges for each Division towards equalization, rather than away from equalization of volumetric rates (Attorney General Brief at 196). The Attorney General asserts that a smaller increase in the customer charge for the Colonial Division will result in a less significant difference between Boston Division and Colonial Division volumetric charges and, therefore, is more reasonable than National Grid's approach (Attorney General Brief at 196).

ii. Company

National Grid claims that it is appropriate to increase customer charges before volumetric charges as it more accurately reflects the results of the ACOSS and revenue allocation (Company Brief at 323, citing Exhs. NG-PP-Rebuttal at 11; DPU 44-5). The Company also asserts that its proposed PBR plan contemplates making rate adjustments to only volumetric and demand rates, not customer charges (Company Brief at 324, citing Exhs. NG-PP-Rebuttal at 12; DPU 44-5).

c. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-41B is $36.66 per month, for Rate G-41C is $52.15 per month, and for Rate G-41E is $63.67 per month (Exhs. NG-PP-1, at 47; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $26.00 for Rates G-41B and G-41E best meets our rate design goals and objectives. The proposed $19.00 customer charge for Rate G-41C also meets our rate design goals and objectives, better reflects the results of the ACOSS, and furthers the Company's plan to consolidate rate classes. Accordingly, the Department approves the customer charge of $19.00 per month. The Company shall set the volumetric rates for Rates G-41B, G-41C, and G-41E to recover the remaining class revenue requirements approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

4. C&I Rate G-42 (Low Load Factor General Service Rate – Medium)

a. Introduction

The Company proposes Rates G-42B, G-42C, and G-42E to serve certain medium C&I customers in the Boston Division, Colonial Division, and Essex Division, respectively. As discussed in Section XIII.D above, the Company proposes to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of service territory. For the Rate G-42 classes, the Company proposes to increase the customer charge for Rate G-42C to equal that of Rates G-42B and G-42E (Exh. NG-PP-7(a)). The Company proposes increases to all volumetric G-42 rates, in amounts that vary by division territory (Exh. NG-PP-7(a)).

Rate G-42B is available to C&I customers located in the Boston Division whose metered use in the most recent peak season is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 501 CfH and 1,500 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 36). The Company's current and proposed customer charge is $48.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 36). The Company proposes to collect the remaining class revenue requirement through rates of $0.5490 per therm during peak months and $0.4409 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 36).

Rate G-42C is available to C&I customers located in the Colonial Division whose metered use in the most recent peak season is greater than or equal to 72 percent of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is greater than or equal to 20,000 therms and less than or equal to 100,000 therms (billing units) (Exh. NG-PP-10, proposed M.D.P.U. No. 37). The Company proposes to increase the monthly customer charge for Rate G-42C from $31.00 per month to $48.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 37). The Company proposes to collect the remaining class revenue requirement through rates of $0.4204 per therm during peak months and $0.3682 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 37).

Rate G-42E is available to C&I customers located in the Essex Division whose metered use in the most recent peak season is greater than or equal to 73 percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is greater than 22,000 therms but equal to or less than 100,000 therms (Exh. NG-PP-10, proposed M.D.P.U. No. 38)). The Company's current and proposed customer charge is $48.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 38). The Company proposes to collect the remaining class revenue requirement through rates of $0.5052 per therm during peak months and $0.4075 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 38). No intervenor commented on the Company's proposals on brief.

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-42B is $105.53 per month, for Rate G-42C is $378.64 per month, and for Rate G-42E is $397.68 per month (Exhs. NG-PP-1, at 48; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $48.00 for Rates G-42B and G-42E best meets our rate design goals and objectives, and we approve this customer charge. The proposed $48.00 customer charge for Rate G-42C also meets our rate design goals and objectives, better reflects the results of the ACOSS, and furthers the Company's plan to consolidate rate classes, and we approve this customer charge. The Company shall set the volumetric rates for Rates G-42B, G-42C, and G-42E to recover the remaining class revenue requirements approved in this Order.

5. C&I Rate G-43 (Low Load Factor General Service Rate – Large)

a. Introduction

The Company proposes Rates G-43B, G-43C, and G-43E to serve certain large C&I customers in the Boston Division, Colonial Division, and Essex Division, respectively. As discussed in Section XIII.D above, the Company proposes to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of the division territory that they are served on. However, the customer charges already are equal for all G-43 rate classes and the Company proposes no change to those charges at this time (Exh. NG-PP-7(a)). The Company proposes increases to all volumetric G-43 rates, in amounts that vary by division territory (Exh. NG-PP-7(a)).

Rate G-43B is available to C&I customers located in the Boston Division whose metered use in the most recent peak season period is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 1,501 CfH and 12,000 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 39). The Company's current and proposed customer charge is $125.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 39). The Company proposes to collect the remaining class revenue requirement through rates of $0.4576 per therm during peak months and $0.3981 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 39).

Rate G-43C is available to C&I customers located in the Colonial Division whose metered use in the most recent peak season is greater than or equal to 72 percent of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is greater than 100,000 therms (billing units) (Exh. NG-PP-10, proposed M.D.P.U. No. 40). The Company's current and proposed customer charge is $125.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed

M.D.P.U. No. 40). The Company proposes to collect the remaining class revenue requirement through rates of $0.3760 per therm during peak months and $0.2426 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 40).

Rate G-43E is available to C&I customers located in the Essex Division whose metered use in the most recent peak season is greater than or equal to 73 percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is greater than 100,000 therms (Exh. NG-PP-10, proposed M.D.P.U. No. 41). The Company's current and proposed customer charge is $125.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 41). The Company proposes to collect the remaining class revenue requirement through rates of $0.4576 per therm during peak months and $0.3981 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 41). No intervenor commented on the Company's proposals on brief.

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-43B is $209.60 per month, for Rate G-43C is $456.54 per month, and for Rate G-43E is $990.28 per month (Exhs. NG-PP-1, at 48; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $125.00 for Rates G-43B, G-43C, and G-43E best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rates for Rates G-43B, G-43C, and G-43E to recover the remaining class revenue requirements approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

6. C&I Rate G-44B (Low Load Factor General Service Rate – Extra-Large)

a. Introduction

The Company proposes Rate G-44B to serve extra-large C&I customers in the Boston Division whose metered use in the most recent peak season is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is greater than 12,000 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 42). The Company's current and proposed customer charge is $553.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 42). The Company proposes to collect the remaining class revenue requirement through rates of $6.8158 per maximum daily contract quantity ("MDCQ") during peak months, and $2.3648 per MDCQ during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 42). No intervenor commented on the Company's proposal on brief.

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-44B is $1,047.14 per month (Exh. NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $553.00 for Rate G-44B best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rate for Rate G-44B to recover the remaining class revenue requirement approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

7. C&I Rate G-51 (High Load Factor General Service Rate – Small)

a. Introduction

The Company proposes Rates G-51B, G-51C, and G-51E to serve certain small C&I customers in the Boston Division, Colonial Division, and Essex Division, respectively. As discussed in Section XIII.D above, the Company proposes to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of their division territory. Also, similar to the Rate G-41 classes, the Company proposes to increase the customer charge for Rate G-51C to approach but not yet equal that of Rates G-51B and G-51E (Exh. NG-PP-7(a)). The Company proposes increases to all volumetric G-51 rates, in amounts that vary by division territory (Exh. NG-PP-7(a)).

Rate G-51B is available to C&I customers located in the Boston Division whose metered use in the most recent peak season is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is less than or equal to 500 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 43). The Company's current and proposed customer charge is $26.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 43). The Company proposes to collect the remaining class revenue requirement through rates of $0.4532 per therm during peak months and $0.4061 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 43).

Rate G-51C is available to C&I customers located in the Colonial Division whose metered use in the most recent peak season is less than 72 percent of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is 20,000 therms or less (billing units) (Exh. NG-PP-10, proposed M.D.P.U. No. 44). The Company proposes to increase the monthly customer charge for Rate G-51C from $13.00 per month to $19.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 44). The Company proposes to collect the remaining class revenue requirement through rates of $0.3522 per therm during peak months and $0.3218 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 44).

Rate G-51E is available to C&I customers located in the Essex Division whose metered use in the most recent peak season is less than 73 percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is 45,000 therms or less (Exh. NG-PP-10, proposed M.D.P.U. No. 45). The Company's current and proposed customer charge is $26.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 45). The Company proposes to collect the remaining class revenue requirement through rates of $0.4532 per therm during peak months and $0.4061 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 45).

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

The Attorney General's and Company's positions on the G-41 rates, which is found in Section XIII.E.3.b above, also applies to the G-51 rates.

c. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-51B is $36.74 per month, for Rate G-51C is $70.42 per month, and for Rate G-51E is $85.58 per month (Exhs. NG-PP-1, at 48; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $26.00 for Rates G-51B and G-51E best meets our rate design goals and objectives, and we approve this customer charge. The proposed $19.00 customer charge for Rate G-51C also meets our rate design goals and objectives, better reflects the results of the ACOSS, and furthers the Company's plan to consolidate rate classes, and we approve this customer charge. The Company shall set the volumetric rates for Rates G-51B, G-51C, and G-51E to recover the remaining class revenue requirements approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

8. C&I Rate G-52 (High Load Factor General Service Rate – Medium)

a. Introduction

The Company proposes Rates G-52B, G-52C, and G-52E to serve certain medium commercial, industrial, or institutional customers in the Boston Division, Colonial Division, and Essex Division, respectively. As discussed in Section XIII.D above, the Company is proposing to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of their division territory. For the Rate G-52 classes, the Company proposes to increase the customer charge for Rate G-52C from $31.00 to $48.00, to equal that of Rates G-52B and G-52E. The Company proposes increases to all volumetric G-52 rates, in amounts that vary by division territory.

Rate G-52B is available to C&I customers located in the Boston Division whose metered use in the most recent peak season is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 501 CfH and 1,500 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 46). The Company's current and proposed customer charge is $48.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 46). The Company proposes to collect the remaining class revenue requirement through rates of $0.4112 per therm during peak months and $0.3764 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 46).

Rate G-52C is available to C&I customers located in the Colonial Division whose metered use in the most recent peak period is less than 72 percent of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is greater than or equal to 20,000 therms and less than or equal to 100,000 therms (billing units) (Exh. NG-PP-10, proposed M.D.P.U. No. 47). The Company proposes to increase the monthly customer charge for Rate G-52C from $31.00 per month to $48.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 47). The Company proposes to collect the remaining class revenue requirement through rates of $0.3323 per therm during peak months and $0.3033 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 47).

Rate G-52E is available to commercial, industrial, and institutional customers located in the Essex Division whose metered use in the most recent peak period is less than 73 percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is greater than 45,000 therms but equal to or less than 180,000 therms (Exh. NG-PP-10, proposed M.D.P.U. No. 48). The Company's current and proposed customer charge is $48.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 48). The Company proposes to collect the remaining class revenue requirement through rates of $0.4112 per therm during peak months and $0.3764 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 48). No intervenor commented on the Company's proposals on brief.

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-52B is $92.99 per month, for Rate G-52C is $250.01 per month, and for Rate G-52E is $541.66 per month (Exhs. NG-PP-1, at 48; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $48.00 for Rate G-52B and G-52E best meets our rate design goals and objectives. The proposed $48.00 customer charge for Rate G-52C also meets our rate design goals and objectives, better reflects the results of the ACOSS, and furthers the Company's plan to consolidate rate classes. Accordingly, we approve this customer charge of $48.00 per month. The Company shall set the volumetric rates for Rates G-52B, G-52C, and G-52E to recover the remaining class revenue requirements approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

9. C&I Rate G-53B and G-53C (High Load Factor General Service Rate – Large)

a. Introduction

The Company proposes Rates G-53B and G-53C to serve certain large C&I customers in the Boston Division and Colonial Division, respectively. As discussed in Section XIII.D above, the Company proposes to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of the division territory that they are served on. However, the customer charges already are equal for G-53B and G-53C rate classes and the Company proposes no change to those charges. The Company proposes increases to all volumetric G-53B and G-53C rates, in amounts that vary by division territory.

Rate G-53B is available to C&I customers located in the Boston Division whose metered use in the most recent peak season is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 1,501 CfH and 12,000 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 49). The Company's current and proposed customer charge is $125.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 49). The Company proposes to collect the remaining class revenue requirement through rates of $0.3481 per therm during peak months and $0.3232 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 49).

Rate G-53C is available to C&I customers located in the Colonial Division whose metered use in the most recent peak season is less than 72 percent of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is greater than 100,000 therms (billing units) (Exh. NG-PP-10, proposed M.D.P.U. No. 50). The Company's current and proposed customer charge is $125.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 50). The Company proposes to collect the remaining class revenue requirement through rates of $0.2912 per therm during peak months and $0.2678 per therm during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 50). No intervenor commented on the Company's proposals on brief.

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-53B is $200.42 per month and for Rate G-53C is $508.77 per month (Exhs. NG-PP-1, at 48; NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $125.00 for Rates G-53B and G-53C best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rates for Rates G-53B and G-53C to recover the remaining class revenue requirements approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

10. C&I Rate G-53E (High Load Factor General Service Rate – Large) and G-54B (High Load Factor General Service Rate – Extra Large)

a. Introduction

The Company proposes Rates G-53E and G-54B to serve certain large and extra-large C&I customers in the Boston Division and Colonial Division, respectively. As discussed in Section XIII.D above, the Company proposes to equalize rates or move towards equalization of rates for all customers with similar characteristics regardless of the division territory that they are served on. However, the customer charges already are equal for G-53E and G-54B rate classes and the Company proposes no change to those charges. The Company proposes changes to all volumetric G-53E and G-54B rates, in amounts that vary by division territory.

Rate G-53E is available to C&I customers located in the Essex Division whose metered use in the most recent peak season is less than 73 percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is greater than 180,000 therms (Exh. NG-PP-10, proposed M.D.P.U. No. 51). The Company's current and proposed customer charge is $553.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 51). The Company proposes to collect the remaining class revenue requirement through rates of $6.8244 per MDCQ during peak months and $2.4556 per MDCQ during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 51).

The Company proposes Rate G-54B to serve extra-large customers in the Boston Division whose metered use in the most recent season period is less 70 percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is greater than 12,000 CfH (Exh. NG-PP-10, proposed M.D.P.U. No. 52). The Company's current and proposed customer charge is $553.00 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 52). The Company proposes to collect the remaining class revenue requirement through rates of $6.8244 per MDCQ during peak months and $2.4556 per MDCQ during off-peak months (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 52). No intervenor commented on the Company's proposals on brief.

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-53E is $593.24 per month and for Rate G-54B is $1,333.46 per month (Exh. NG-PP-4(a) at row 68). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $553.00 for Rates G-53E and G-54B best meets our rate design goals and objectives, and we approve this customer charge. The Company shall set the volumetric rates for Rates G-53E and G-54B to recover the remaining class revenue requirements approved in this Order using the same allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons.

11. Street Lighting Rate G-7B

a. Introduction

The Company proposes Rate G-7B to serve any customer located in the Boston Division for gas used for the purpose of street lighting (Exh. NG-PP-10, proposed

M.D.P.U. No. 53). The Company's current fixed charge per lamp is $15.59 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 53). The Company proposes to increase this charge to $19.13 per month Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 53). No intervenor commented on the Company's proposal on brief.

b. Analysis and Findings

The Company proposes to develop its monthly street lighting rate by dividing the class revenue requirement by the number of test year lamps served on Rate G-7B, and then dividing by twelve. As the approved revenue requirement for this rate class has decreased relative to that originally filed by the Company, the Department directs the Company to recalculate the monthly street lighting rate for Rate G-7B using the using its proposed method and the Department approved revenue requirement for this rate class.

12. Outdoor Gas Lighting Rate G-17

a. Introduction

The Company proposes Rates G-17B and G-17C to serve any customer located on private property in the Boston Division or Colonial Division, respectively, for outdoor gas lighting where a standard gas light is attached to the Company's existing distribution system and when it is not feasible (a) to meter gas for such lighting along with other gas used on the premises and (b) to bill the same under the rate in effect for all other service (Exh. NG-PP-10, proposed M.D.P.U. Nos. 54, 55). For Rate G-17B, the Company's current fixed charge per light is $25.93 per month (Exh. NG-PP-7(a)). The Company proposes to increase this charge to $30.54 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 54). For Rate G-17C, the Company's current fixed charge per light is \$2.57 per month (Exh. NG-PP-7(a)). The Company proposes to increase this charge to \$3.97 per month (Exhs. NG-PP-7(a); NG-PP-10, proposed M.D.P.U. No. 55). No intervenor commented on the Company's proposals on brief.

b. Analysis and Findings

The Company proposes to develop its monthly street lighting rate for these classes by dividing the class revenue requirement by the number of test year lights served on each Rate and then dividing by twelve. As the approved revenue requirements for these rate classes have decreased relative to that proposed by the Company, the Department directs the Company to recalculate the monthly street lighting rate for the Rates G-17B and G-17C classes using its proposed method and the Department approved revenue requirement for these rate classes.

XIV. TARIFF CHANGES

A. Distribution Service Terms and Conditions

1. Introduction

National Grid proposes revisions to its Distribution Service Terms and Conditions tariff to account for the Boston Gas-Colonial Gas merger, to better reflect its actual business practices and current market conditions related to the Customer Choice Program,[239] and to

[239] The Customer Choice Program allows customers to purchase natural gas from an authorized supplier (Exh. NG-EDA-1, at 3).

correct typographical errors (Exhs. NG-EDA-1, at 3, 5-9, 10-11; NG-PP-10, proposed M.D.P.U. No. 4.4).

National Grid also proposes new language in Section 5.1 of its Distribution Service Terms and Conditions tariff (Exh. NG-PP-10, proposed M.D.P.U. No. 4.4, § 5.1). The proposed language gives customers notice that the Company may communicate non-emergency issues by whatever means the Company deems appropriate. The proposed language provides:

> … By accepting Distribution Service from the Company pursuant to these Terms and Conditions, a Customer expressly consents to the Company, or anyone working on the Company's behalf, contacting the Customer regarding issues related to Distribution Service and billing and payment, by any method including telephone, autodialed and prerecorded/artificial voice calls, email, text, and/or letter. By contacting the Company, a Customer may opt-out of receiving non-emergency communications through certain methods.

(Exh. NG-PP-10, proposed M.D.P.U. No. 4.4, § 5.1).

The Company states that the proposed language was developed to facilitate communication with customers consistent with the requirements of the federal Telephone Consumer Protection Act ("TCPA"), 47 U.S.C. § 227 et seq. (Exh. NG-JRK-Rebuttal-1, at 4). According to the Company, the Federal Communications Commission ("FCC"), in interpreting the TCPA, has determined that utility companies may make autodialed calls and send automated texts to their customers concerning matters closely related to the utility service (Exh. NG-JRK-Rebuttal-1, at 4). Further, the Company states that the FCC has found that a customer who provided a wireless telephone number, or later updated its contact information, is deemed to have given prior express consent to be contacted by its utility company for calls that are closely related to the utility service, unless the customer has provided instructions to the contrary (Exh. NG-JRK-Rebuttal-1, at 4-5).[240]

National Grid states that the proposed language is designed to eliminate uncertainty regarding whether customers have consented to receive these types of communications (Exh. NG-JRK-Rebuttal-1, at 5). The Company also notes that the Department approved the same language in D.P.U. 18-150, and that the provision is included in Massachusetts Electric Company's Terms and Conditions for Distribution Service (Exh. NG-JRK-Rebuttal-1, at 5).

Finally, National Grid notes that the Company is not proposing to change its obligations to follow other tariff rules regarding past-due notices, disconnect notices, and termination of service, and that the proposed tariff provision does not automatically designate new customers to receive paperless bills (Exh. NG-JRK-Rebuttal-1, at 7).

2. Positions of the Parties

a. Attorney General

The Attorney General objects to the Company's proposed revision to Section 5.1 of its Distribution Service Terms and Conditions tariff and asserts that the provision is inconsistent with the public interest (Attorney General Brief at 179, 221-222). The Attorney General

---

240 National Grid states that it recently completed an IT project that modified the Company's customer service systems and integrated applications to capture and to better track customers' consent, including instances where customers have revoked consent, as well as to address incorrect phone numbers (Exh. NG-JRK-Rebuttal-1, at 6). According to the Company, a customer service representative can clearly see whether a customer has chosen to have any phone number stricken from contact for non-emergency purposes (Exh. NG-JRK-Rebuttal-1, at 6).

argues that although a customer may opt-out of receiving non-emergency communications through certain methods, the default is that the Company may contact customers by any method (Attorney General Brief at 221). Further, the Attorney General contends that the proposed language could be interpreted as allowing the Company to deliver bills by email or text message without the customer's consent (Attorney General Brief at 222, citing Exh. AG-SJR-1, at 29 (Rev.)). In addition, the Attorney General claims that the provision could apply to the receipt of past-due notices, dishonored payments notices, or other notifications requiring customers to act within a fairly short period of time or incur penalties (or even have service disconnected) (Attorney General Brief at 222, citing Exh. AG-SJR-1, at 29 (Rev.)). Moreover, she argues that the express consent provision of the proposed condition places a host of burdens on the customer without first ensuring that the customer is aware of the potential changes and associated burdens (Attorney General Brief at 222, citing Exh. AG-SJR-1, at 29-30 (Rev.)).[241]

For these reasons, the Attorney General recommends that the Department reject National Grid's request to revise Section 5.1 of its proposed Distribution Service Terms and Conditions tariff (Attorney General Brief at 222).

---

[241] The Attorney General argues that the customer: (1) may incur costs related to the communication from the Company, such as from text messages; (2) may not know how to contact the Company to make changes to how he/she receives communications; (3) may be exposed to unauthorized parties gaining access to his/her account; and (4) may not receive a bill in the expected manner (Attorney General Brief at 222, citing Exh. AG-SJR-1, at 29-30 (Rev.)).

b. <u>TEC</u>

TEC does not address any of the Company's specific tariff changes. On brief, however, TEC urges the Department to consider a six-month working group of interested stakeholders to examine allowing customers access to their daily usage data, and, as part of that process, to consider business plans to achieve the access goal for customers (TEC Brief at 8). TEC represents that the Company is amenable to establish the working group (TEC Brief at 8, <u>citing</u> RR-TEC-2).

c. <u>Company</u>

On brief, National Grid summarized the various proposed tariff changes in this proceeding but did not specifically address proposed language in Section 5.1 of its Distribution Service Terms and Conditions (Company Brief at 312-316). National Grid, however, acknowledged that, pursuant to directives issued in D.P.U. 19-120, the Company is part of a working group of all gas distribution companies, licensed gas suppliers and marketers, the Attorney General, and other interested parties, to participate in a collaborative effort to reach a consensus on updating the model supplier-related Distribution Service Terms and Conditions by September 30, 2021 (Company Brief at 316, <u>citing</u> D.P.U. 19-120, at 475-476). The Company claims that it is actively involved in the working group and that it sought and received feedback on its proposed distribution terms and conditions changes (Company Brief at 316, <u>citing</u> Exh. NG-EDA-1, at 14-15). Further, the Company argues that any proposed changes to its Distribution Service Terms and Conditions are "minor" or "ministerial" and designed to match the Company's current practices (Company Brief at 316). For these reasons, the Company asserts that the Department should approve the proposed changes to its Distribution Service Terms and Conditions tariff (Company Brief at 316).

3. Analysis and Findings

Approved tariffs have the force and effect of law as long as they satisfy the basic requirement of reasonableness. Maryland Gas Company v. NSTAR Gas Company, 471 Mass. 416, 422 (2015). The Department will review National Grid's proposed tariff changes based on a standard of reasonableness.[242]

First, as noted, the Attorney General challenges the Company's proposed revisions to Section 5.1 regarding customer communication. No other intervenor commented on the Company's proposal. We also note that the same language was approved in D.P.U. 18-150 for Massachusetts Electric Company and Nantucket Electric Company without objection from the Attorney General or any other party. D.P.U. 18-150, Stamp-Approved Compliance Filing (November 1, 2019); M.D.P.U. No. 1412, § II.2A.

The Department has reviewed the proposed language as well as the positions of Company and Attorney General. We find that the purpose of proposed language in Section 5.1 is to clarify that the Company is permitted to contact customers about non-emergency issues related to distribution service, billing, and payment. Further, given the increase in methods and manners of communication, it stands to reason that there should

---

[242] Where a proposed tariff change affects consumer protection, the Department may apply a public interest where the context requires.

be a similar increase in the methods and manners available to a utility to convey non-emergency information to its customers, particularly if a customer has provided certain contact information to the utility. As such, we are not persuaded by the Attorney General's arguments.

The Company acknowledges that the proposed provision is not intended to change its current practices with respect to past-due notices, disconnect notices, and termination of service, and that the proposed provision does not automatically designate new customers to receive paperless bills (Exh. NG-JRK-Rebuttal-1, at 7). We fully expect the Company to adhere to these representations. Further, to the extent a customer indicates his or her desire to opt out of receiving such communications, the Company shall accept the customer's decision and cease further communication. Based on the above considerations and findings, the Department concludes that the proposed revision to Section 5.1 of the Distribution Service Terms and Conditions tariff is reasonable, and, therefore, we approve the revisions.

Next, the Department has reviewed the remaining proposed revisions to the Company's Distribution Service Terms and Conditions, including those related to the Customer Choice Program and various administrative fees and charges,[243] and the record supporting the changes (Exhs. NG-EDA-1, at 5-9, 10-16; NG-RRP-2, Sch. 2, at 5-7 (Rev. 3); NG-PP-10, proposed M.D.P.U. No. 4.4; AG 18-2; AG 53-1 through AG 53-16;

243 The Company proposed changes to its Returned Check Charge, Account Restoration Charge, Seasonal Restoration Reconnection Fee, and Daily Metered Equipment Fee (Exh. NG-PP-10, proposed M.D.P.U. No. 4.4, App. B).

Tr. 6, at 742-745). No intervenor commented on the Company's proposed revisions on brief. We find the proposed revisions to be reasonable, and, therefore, we approve the changes. In particular, we find that the revised fees and charges are reasonable and based on the costs associated with these functions that the Company actually incurred (Exhs. NG-RRP-2, Sch. 2, at 5-7 (Rev. 3); NG-PP-10, proposed M.D.P.U. No. 4.4, App. B; AG 18-2; AG 53-16 & Att.). D.P.U. 08-35, at 58; Whitinsville Water Company, D.P.U. 89-67, at 4 (1989); D.P.U. 956, at 62. The Company shall file a revised Distribution Service Terms and Conditions tariff with its compliance filing reflecting the proposed revisions.

Finally, TEC urges the Department to consider a working group to examine allowing customers access to their daily usage data and to consider business plans to achieve such access for customers (TEC Brief at 8). The Company is amenable to establishing the working group (RR-TEC-2). Currently, the Company's customers are provided access to post-billing usage information (Exh. TEC 1-4; Tr. 6, at 739). The Department agrees that a small working group to examine the issue of access to customer usage data is appropriate. The Department directs the Company and TEC to discuss these issues and form a working group of interested stakeholder, including other LDCs, as necessary. No later than 45 days from the issuance of this Order, the working group should initiate its first meeting and begin discussing customers' access to daily usage data and how to achieve such access. The working group shall prepare a progress report on these efforts and submit the report to the Department no later than March 31, 2022.

B. Other Tariff Provisions

As noted, the Company proposes changes to its other tariffs to reflect the proposals submitted in this case or to update current tariff language (see generally Exhs. NG-PP-10; NG-PP-11). In the various sections of this Order, the Department has addressed Company proposals that also will implicate a number of the proposed tariff changes (e.g., PBR mechanism proposal, exogenous property tax proposal, GBE mechanism proposal, Life-Cycle Integrity Projects proposal). The Department directs the Company to make all appropriate tariff changes consistent with the Department's findings in those sections. The Department has reviewed all remaining proposed tariff changes not specifically addressed in this Order or not associated with an issue that is specifically addressed in this Order, including the Residential Automatic Meter Reading Opt-Out Provision, proposed M.D.P.U. No. 57, and the associated fee changes with this provision. No intervenor commented on any of these proposed changes on brief. We find the proposed changes to be reasonable, and, therefore, we approve the changes. In particular, we find that the revised fees associated with the Residential Automatic Meter Reading Opt-Out Provision are based on the costs associated with these functions that the Company actually incurred (Exh. NG-RRP-2, Sch. 2, at 8 (Rev. 3)). D.P.U. 08-35, at 58; D.P.U. 89-67, at 4; D.P.U. 956, at 62. The Company shall file revised tariffs with its compliance filing reflecting the proposed changes.

XV. SCHEDULES

A. Schedule 1 – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	400,197,395	(10,365,783)	(15,691,241)	374,140,371
Depreciation & Amortization	221,198,657	(696,871)	(23,413,783)	197,088,003
Taxes Other Than Income Taxes	87,703,223	11,589,016	(4,393,449)	94,898,790
Interest on Customer Deposits	17,254	16,547	0	33,801
Income Taxes	52,672,309	(109,749)	(7,780,686)	44,781,873
Return on Rate Base	224,029,336	(289,225)	(21,699,984)	202,040,127
Uncollectible O&M Due to Increase	3,745,379	(286,502)	(1,171,084)	2,287,793
Total Cost of Service	989,563,553	(142,568)	(74,150,227)	915,270,758
OPERATING REVENUES				
Operating Revenues*	747,919,987	152,324	0	748,072,311
Revenue Adjustments	20,906,735	1,434,178	0	22,340,913
Total Operating Revenues	768,826,722	1,586,502	0	770,413,224
Total Revenue Deficiency	**220,736,831**	**(1,729,070)**	**(74,150,227)**	**144,857,534**

*** Includes a Revenue Offset of $43,576,021 associated with Special Contract Revenues.**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

B. Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
O&M Per Books	533,860,915	253,154	0	534,114,069
Normalizing Adjustments	(180,153,948)	290,788	0	(179,863,160)
Test Year O&M Expense	353,706,967	543,942	0	354,250,909
ADJUSTMENTS TO TEST YEAR O&M EXPENSE:				
Labor	10,311,573	260,803	0	10,572,376
Health Care	544,256	(909,736)	(114,915)	(480,395)
Group Life & Other Insurance	43,220	1,128	0	44,348
Thrift Plan	331,227	8,641	(339,868)	0
FAS 112/ ASC 712	0	0	0	0
Service Company Rents	6,294,858	(1,795,323)	(237,651)	4,261,884
Joint Facilities	0	0	(146,075)	(146,075)
Uninsured Claims	0	0	0	0
Insurance Premium	242,927	230,303	0	473,230
Regulatory Assessment Fees	(155,438)	(32,029)	0	(187,467)
Uncollectible Accounts	(3,654,276)	(1,920,958)	0	(5,575,234)
Postage	56,025	97,416	0	153,441
Gas Acquisition Costs	0	0	0	0
Hardship Protected Accounts	5,689,122	(1,447,751)	0	4,241,371
Paperless Bill Credit	0	0	0	0
Post-Retirement Benefits Other than Pension	0	0	0	0
Pension	0	0	0	0
Energy Efficiency Program	0	0	0	0
Other O&M Expenses*	3,357,026	(1,941,207)	(866,840)	548,979
Third-Party Rent			(813,673)	
Caregiver Program			(31,611)	
Non-Industry Dues & Memberships			(21,556)	
Gas Safety and Damage Prevention	18,620,631	(6,518,132)	(5,955,665)	6,146,834
Rate Case Expense	0	340,345	0	340,345
Gas Business Enablement Program**	0	0	(7,887,387)	(7,887,387)
Applicable Inflation	4,809,277	2,716,775	(142,840)	7,383,212
Sum of O&M Expense Adjustments	46,490,428	(10,909,725)	(15,691,241)	19,889,462
Distribution O&M Expense	**400,197,395**	**(10,365,783)**	**(15,691,241)**	**374,140,371**

*** Includes adjustments for third party rent, caregiver program, and non-industry dues & memberships.**
**** Per Company numbers included in various categories.**

C. Schedule 2A – Inflation Table

Normalized Test Year O&M Expense*:	$354,250,909
Less Company Adjustments:	
Labor	$149,415,380
Healthcare	$19,099,422
Group Life & Other Insurance	$626,381
Thrift Plan	$4,800,385
Service Company Rents	$16,111,159
Insurance Premium	$2,555,593
Regulatory Assessment Fees	$4,671,285
Uncollectible Accounts	$20,893,159
Postage	$4,180,955
Paperless Bill Credit	$1,258,402
Other O&M Expenses	$8,677,880
Rate Case Expenses	$253,154
Total Company O&M Adjustments:	$232,543,155
Residual O&M Expenses Subject to Inflation	$121,707,754
Inflation Factor:	6.14%
Inflation Allowance @ 6.14%	$7,472,856
Less: Department Adjustments	
Non-industry dues and memberships	$21,556
Caretaker Expense	$31,611
Contractor Costs	$1,260,762
Joint Facilities	$146,075
Department Sub-total	$1,460,004
Residual O&M Expense Subject to Inflation	$120,247,750
Inflation Factor:	6.14%
Inflation Allowance per DPU	$7,383,212

* The DPU subtracted the amount of $866,370 for the Gas Acquisition Costs

D. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	208,091,484	(68,040)	(23,413,783)	184,609,661
Merger Savings Allowance	12,300,000	0	0	12,300,000
Farm Discount	180,101	0	0	180,101
Sale of Land	0	(1,759)	0	(1,759)
Normalized Rate Case Expenses	627,072	(627,072)	0	0
Total Depreciation and Amortization Expense	**221,198,657**	**(696,871)**	**(23,413,783)**	**197,088,003**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

E. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	6,486,883,675	(3,078,217)	(134,660,931)	6,349,144,527
LESS:				
Reserve for Depreciation and Amortization	(2,157,179,502)	(881,699)	250,164	(2,157,811,036)
Net Utility Plant in Service	4,329,704,173	(3,959,916)	(134,410,767)	4,191,333,490
ADDITIONS TO PLANT:				
Cash Working Capital	60,631,758	1,127,271	(2,374,970)	59,384,060
Other Materials and Supplies	15,938,471	0	0	15,938,471
Heel Gas Inventory - Storage	2,546,204	0	0	2,546,204
Heel Gas Inventory - LNG	2,657,302	198,805	0	2,856,107
Total Additions to Plant	81,773,736	1,326,076	(2,374,970)	80,724,843
DEDUCTIONS FROM PLANT:				
Work in Progress	(283,400,895)	0	0	(283,400,895)
Plant Held for Future Use	(515,704)	0	0	(515,704)
Contributions in Aid of Construction	(84,737,346)	0	0	(84,737,346)
Reserve for Deferred Income Tax	(674,181,854)	(1,269,335)	13,233,027	(662,218,161)
Estimated Excess Deferred Taxes	(258,432,695)	0	(1,324,282)	(259,756,977)
Amortization of Intangible Plant	(85,985,429)	0	0	(85,985,429)
Customer Deposits	(886,130)	0	0	(886,130)
Total Deductions from Plant	(1,388,140,053)	(1,269,335)	11,908,745	(1,377,500,643)
RATE BASE	3,023,337,856	(3,903,174)	(124,876,992)	2,894,557,691
COST OF CAPITAL	7.41%	0.00%	-0.43%	6.98%
RETURN ON RATE BASE	**224,029,336**	**(289,225)**	**(21,699,984)**	**202,040,127**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

F. Schedule 5 – Cost of Capital

	PER COMPANY			
	PRINCIPAL ($000s)	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	1,846,000	46.56%	3.86%	1.80%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	2,118,432	53.44%	10.50%	5.61%
Total Capital	3,964,432	100.00%		7.41%
Weighted Cost of				
Debt				1.80%
Preferred				0.00%
Equity				5.61%
Cost of Capital				7.41%

	COMPANY ADJUSTMENTS			
	PRINCIPAL ($000s)	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	1,846,000	46.56%	3.86%	1.80%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	2,118,432	53.44%	10.50%	5.61%
Total Capital	3,964,432	100.00%		7.41%
Weighted Cost of				
Debt				1.80%
Preferred				0.00%
Equity				5.61%
Cost of Capital				7.41%

	PER ORDER			
	PRINCIPAL ($000s)	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	1,846,000	46.56%	3.86%	1.80%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	2,118,432	53.44%	9.70%	5.18%
Total Capital	3,964,432	100.00%		6.98%
Weighted Cost of				
Debt				1.80%
Preferred				0.00%
Equity				5.18%
Cost of Capital				6.98%

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

G. Schedule 6A – Cash Working Capital – Boston Gas Company

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total O&M Expense	332,485,555	(9,252,680)	(10,655,537)	312,577,339
Less: Uncollectible Accounts	13,886,351	(1,007,926)	0	12,878,425
Paperless Bill Credit	1,019,203	0		1,019,203
Rate Case Expense	0	484,414		484,414
Municipal Tax	63,866,185	9,398,111	(3,523,031)	69,741,265
Payroll Taxes: FICA, FUTA, and SUTA	10,233,200	59	0	10,233,259
Reconciliation to Initial Filing	1,011,549	(1,011,549)	0	0
Payroll Tax	11,244,749	(1,011,490)	0	10,233,259
Other Withholding	33,489,239	0	0	33,489,239
Add: Total Taxes Other Than Income Taxes	108,600,173	8,386,621	(3,523,031)	113,463,763
Amount Subject to Cash Working Capital	426,180,174	(342,547)	(14,178,568)	411,659,060
Cash Working Capital Factor	12.27%	-253.52%	12.48%	12.48%
Cash Working Capital Allowance	**52,293,865**	**868,415**	**(1,770,076)**	**51,392,205**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

H. Schedule 6B – Cash Working Capital – Colonial Gas Company

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total O&M Expense	67,711,840	(1,113,103)	(5,035,702)	61,563,035
Less: Uncollectible Accounts	2,572,040	(132,540)	0	2,439,500
Paperless Bill Credit	239,199	0	0	239,199
Rate Case Expense	0	109,085	0	109,085
Municipal Tax	10,684,737	2,192,499	(870,418)	12,006,818
Payroll Taxes: FICA, FUTA, and SUTA	2,586,994	(2,780)	0	2,584,214
Reconciliation to Initial Filing	87,981	(87,981)	0	0
Payroll Tax	2,674,975	(90,761)	0	2,584,214
Other Withholding	6,549,102	0	0	6,549,102
Add: Total Taxes Other Than Income Taxes	19,908,814	1,969,198	(870,418)	21,007,594
Amount Subject to Cash Working Capital	84,809,415	879,550	(5,906,120)	79,782,845
Cash Working Capital Factor	9.83%	29.43%	10.02%	10.02%
Cash Working Capital Allowance	**8,337,893**	**258,856**	**(604,894)**	**7,991,856**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

I. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Municipal Taxes	67,152,579	0	0	67,152,579
Payroll Taxes	13,698,832	0	0	13,698,832
Other Taxes	(240,772)	0	0	(240,772)
	80,610,639	0	0	80,610,639
Adjustments to Taxes Other Than Income				
Normalizing Adjustments				
Municipal Taxes	(7,700)	0	0	(7,700)
Payroll Taxes	(322,249)	0	0	(322,249)
Other Taxes	285,885	0	0	285,885
Known and Measurable Adjustments				
Municipal Taxes	7,406,042	11,590,610	(4,393,449)	14,603,203
Payroll Taxes	(271,153)	(2,605)	0	(273,758)
Other Taxes	1,759	1,011	0	2,770
Total Adjustments	7,092,584	11,589,016	(4,393,449)	14,288,151
Municipal Tax	74,550,921	11,590,610	0	81,748,082
Payroll Tax	13,105,430	(2,605)	0	13,102,825
Taxes Other Than Income	**87,703,223**	**11,589,016**	**(4,393,449)**	**94,898,790**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

J. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	3,023,337,856	(3,903,174)	(124,876,992)	2,894,557,691
Return on Rate Base	224,029,336	(289,225)	(21,699,984)	202,040,127
LESS:				
Interest Expense	54,420,081	(70,257)	(2,247,786)	52,102,038
Amortization of Net Excess Deferred Tax	7,575,545	19,944	(5,819,601)	1,775,888
Amortization of Investment Tax Credit	0	0	0	0
Income Tax Impact of Flow Through Items	818,539	0	0	818,539
Amortization of Net Funded Deferred Tax Liability	(339,071)	0	0	(339,071)
Total Adjustments	62,475,094	(50,313)	(8,067,387)	54,357,394
Taxable Income Base	161,554,241	(238,912)	(13,632,597)	147,682,732
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	222,281,560	(328,718)	(18,757,012)	203,195,830
Massachusetts Income Tax (8%)	17,782,525	(26,297)	(1,500,561)	16,255,666
Federal Taxable Income	204,499,035	(302,420)	(17,256,451)	186,940,163
Federal Income Tax Calculated (21%)	42,944,797	(63,508)	(3,623,855)	39,257,434
Total Income Taxes Calculated	60,727,322	(89,805)	(5,124,416)	55,513,100
Amortization of Net Excess Deferred Tax	(7,575,545)	(19,944)	(2,656,270)	(10,251,759)
Income Tax Impact of Flow Through Items	(818,539)	0	0	(818,539)
Amortization of Net Unfunded Deferred Tax Liability	339,071	0	0	339,071
Total Income Taxes	**52,672,309**	**(109,749)**	**(7,780,686)**	**44,781,873**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

K. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Base Distribution Revenue:				
Firm Revenues	747,786,971	185,773	0	747,972,744
Known and Measurable Adjustments - Special Contracts	133,016	(33,449)	0	99,567
Adjusted Total Firm Revenues	747,919,987	152,324	0	748,072,311
Other Operating Revenue Adjustments:				
Other Revenues	21,087,596	1,432,934	0	22,520,530
Known and Measurable Adjustments - Other Misc Revenue	(180,861)	1,244	0	(179,617)
	20,906,735	1,434,178	0	22,340,913
Operating Revenues	768,874,567	1,618,707	0	770,493,274
Known and Measurable Adjustments	(47,845)	(32,205)	0	(80,050)
Adjusted Total Operating Revenues	768,826,722	1,586,502	0	770,413,224

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

L. Schedule 10 – Allocation to Rate Classes

	TOTAL TEST YEAR REVENUE	TEST YEAR BASE DISTRIBUTION REVENUE	TEST YEAR RECONCILING REVENUE	TOTAL BASE DISTRIBUTION REVENUE AT EROR	BASE DISTRIBUTION REVENUE INCREASE	CHANGE IN RECONCILING REVENUE	REVENUE INCREASE IN EXCESS OF 10% CAP
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
RESIDENTIAL							
NONHEAT (R-1B & R-2B)	29,378,985	19,154,492	10,224,493	23,771,198	4,616,706	6,376	1,685,184
HEAT (R-3B & R-4B)	813,549,490	362,819,717	450,729,773	397,525,270	34,705,553	3,218,207	-
COMMERCIAL (LLF)							
G-41B	53,336,663	24,402,769	28,933,894	27,917,189	3,514,420	279,075	-
G-42B	66,788,306	27,725,731	39,062,575	31,971,525	4,245,794	141,204	-
G-43B	174,659,370	63,273,495	111,385,875	75,169,043	11,895,548	885,248	-
G-44B	76,176,449	27,047,230	49,129,219	31,341,300	4,294,070	754,390	-
COMMERCIAL (HLF)							
G-51B	13,811,373	5,695,253	8,116,120	4,344,193	(1,351,060)	(28,614)	-
G-52B	21,366,043	7,822,549	13,543,494	6,379,908	(1,442,641)	(120,906)	-
G-53B	38,677,533	12,428,333	26,249,200	10,272,931	(2,155,402)	(64,581)	-
G-54B	68,798,775	19,772,154	49,026,621	17,902,070	(1,870,084)	295,935	-
COMMERCIAL (LLF)							
G-41E	12,458,328	4,995,200	7,463,128	7,463,108	2,467,908	72,518	1,294,593
G-42E	6,862,456	2,380,701	4,481,755	3,223,813	843,112	15,515	172,382
G-43E	1,346,667	461,934	884,733	623,243	161,309	8,051	34,694
COMMERCIAL (HLF)							
G-51E	4,334,871	1,626,107	2,708,764	1,583,196	(42,911)	(16,512)	-
G-52E	1,789,538	591,188	1,198,350	367,199	(223,989)	(13,004)	-
G-53E	2,783,238	735,811	2,047,427	644,311	(91,500)	(6,819)	-
LAMPS							
G-07B	1,077,906	538,467	539,439	41,811	(496,656)	(3,141)	-
G-17B	3,404	2,177	1,227	887	(1,290)	(6)	-
RESIDENTIAL							
NONHEAT (R-1C & R-2C)	2,239,223	1,478,594	760,629	2,763,123	1,284,529	9,534	1,070,140
HEAT (R-3C & R-4C)	217,493,684	89,500,921	127,992,763	136,457,238	46,956,317	2,527,831	27,734,780
COMMERCIAL (LLF)							
G-41C	36,201,065	14,189,919	22,011,146	23,206,701	9,016,782	712,357	6,109,032
G-42C	21,041,758	6,699,686	14,342,072	10,815,695	4,116,009	545,082	2,556,915
G-43C	9,523,866	2,700,772	6,823,094	3,710,779	1,010,007	197,906	255,526
COMMERCIAL (HLF)							
G-51C	9,438,268	3,121,043	6,317,225	3,736,977	615,934	137,436	-
G-52C	5,299,442	1,489,117	3,810,325	1,854,928	365,811	115,491	-
G-53C	15,639,567	3,841,455	11,798,112	2,969,973	(871,482)	261,771	-
LAMPS							
G-17C	7,812	1,475	6,337	963	(512)	65	-
TOTAL	1,704,084,080	704,496,290	999,587,790	826,058,572	121,562,281	9,930,412	40,913,246

For illustrative purposes only

	BASE DISTRIBUTION REVENUE ALLOCATOR	ALLOCATION OF BASE DISTRIBUTION INCREASE IN EXCESS OF 10% CAP	BASE DISTRIBUTION REVENUE PER 10% CAP	REVENUE INCREASE IN EXCESS OF 10% CAP	BASE DISTRIBUTION REVENUE ALLOCATOR	BASE DISTRIBUTION INCREASE IN EXCESS OF 10% CAP	BASE DISTRIBUTION REVENUE PER 10% CAP
	(h)	(i)	(j)	(k)	(l)	(m)	(n)
RESIDENTIAL							
NONHEAT (R-1B & R-2B)	-	-	22,086,014	0	-	-	22,086,014
HEAT (R-3B & R-4B)	397,525,270	26,487,658	424,012,928	-	397,525,270	611,191	424,624,119
COMMERCIAL (LLF)							
G-41B	27,917,189	1,860,161	29,777,350	319,990	-	-	29,457,360
G-42B	31,971,525	2,130,307	34,101,832	-	31,971,525	49,156	34,150,988
G-43B	75,169,043	5,008,617	80,177,660	323,477	-	-	79,854,184
G-44B	31,341,300	2,088,314	33,429,614	-	31,341,300	48,187	33,477,801
COMMERCIAL (HLF)							
G-51B	4,344,193	289,460	4,633,653	-	4,344,193	6,679	4,640,332
G-52B	6,379,908	425,102	6,805,010	-	6,379,908	9,809	6,814,819
G-53B	10,272,931	684,500	10,957,430	-	10,272,931	15,795	10,973,225
G-54B	17,902,070	1,192,840	19,094,910	-	17,902,070	27,524	19,122,434
COMMERCIAL (LLF)							
G-41E	-	-	6,168,515	0	-	-	6,168,515
G-42E	-	-	3,051,431	0	-	-	3,051,431
G-43E	-	-	588,550	-	-	-	588,550
COMMERCIAL (HLF)							
G-51E	1,583,196	105,491	1,688,687	-	1,583,196	2,434	1,691,121
G-52E	367,199	24,467	391,666	-	367,199	565	392,231
G-53E	644,311	42,931	687,242	-	644,311	991	688,233
LAMPS							
G-07B	41,811	2,786	44,596	-	41,811	64	44,661
G-17B	887	59	946	-	887	1	948
RESIDENTIAL							
NONHEAT (R-1C & R-2C)	-	-	1,692,982	-	-	-	1,692,982
HEAT (R-3C & R-4C)	-	-	108,722,458	0	-	-	108,722,458
COMMERCIAL (LLF)							
G-41C	-	-	17,097,668	-	-	-	17,097,668
G-42C	-	-	8,258,780	0	-	-	8,258,780
G-43C	-	-	3,455,253	-	-	-	3,455,253
COMMERCIAL (HLF)							
G-51C	3,736,977	249,000	3,985,977	58,544	-	-	3,927,434
G-52C	1,854,928	123,596	1,978,524	74,954	-	-	1,903,570
G-53C	2,969,973	197,893	3,167,866	-	2,969,973	4,566	3,172,433
LAMPS							
G-17C	963	64	1,028	-	963	1	1,029
TOTAL	614,023,674	40,913,246	826,058,572	776,964	505,345,537	776,964	826,058,572

For illustrative purposes only

	DISTRIBUTION REVENUE IN EXCESS OF 200% CAP	PER ORDER TOTAL BASE DISTRIBUTION REVENUE	PER ORDER TOTAL DISTRIBUTION REVENUE	PER ORDER TOTAL BASE DISTRIBUTION REVENUE INCREASE (%)	PER ORDER TOTAL REVENUE INCREASE (%)
	(o)	(p)	(q)	(r)	(s)
RESIDENTIAL					
NONHEAT (R-1B & R-2B)	-	22,086,014	32,316,884	15.3	10.0
HEAT (R-3B & R-4B)	-	424,624,119	878,572,099	17.0	8.0
COMMERCIAL (LLF)					
G-41B	-	29,457,360	58,670,329	20.7	10.0
G-42B	-	34,150,988	73,354,767	23.2	9.8
G-43B	-	79,854,184	192,125,307	26.2	10.0
G-44B	-	33,477,801	83,361,410	23.8	9.4
COMMERCIAL (HLF)					
G-51B	-	4,640,332	12,727,838	(18.5)	(7.8)
G-52B	-	6,814,819	20,237,407	(12.9)	(5.3)
G-53B	-	10,973,225	37,157,844	(11.7)	(3.9)
G-54B	-	19,122,434	68,444,990	(3.3)	(0.5)
COMMERCIAL (LLF)					
G-41E	-	6,168,515	13,704,161	23.5	10.0
G-42E	-	3,051,431	7,548,702	28.2	10.0
G-43E	-	588,550	1,481,334	27.4	10.0
COMMERCIAL (HLF)					
G-51E	-	1,691,121	4,383,373	4.0	1.1
G-52E	-	392,231	1,577,577	(33.7)	(11.8)
G-53E	-	688,233	2,728,841	(6.5)	(2.0)
LAMPS					
G-07B	-	44,661	580,959	(91.7)	(46.1)
G-17B	-	948	2,169	(56.5)	(36.3)
RESIDENTIAL					
NONHEAT (R-1C & R-2C)	-	1,692,982	2,463,145	14.5	10.0
HEAT (R-3C & R-4C)	-	108,722,458	239,243,052	21.5	10.0
COMMERCIAL (LLF)					
G-41C	-	17,097,668	39,821,172	20.5	10.0
G-42C	-	8,258,780	23,145,934	23.3	10.0
G-43C	-	3,455,253	10,476,253	27.9	10.0
COMMERCIAL (HLF)					
G-51C	-	3,927,434	10,382,095	25.8	10.0
G-52C	-	1,903,570	5,829,386	27.8	10.0
G-53C	-	3,172,433	15,232,316	(17.4)	(2.6)
LAMPS					
G-17C	-	1,029	7,431	(30.3)	(4.9)
TOTAL	-	826,058,572	1,835,576,773	17.3	7.7

For illustrative purposes only

NOTES:
Col (a): Exh. NG-PP-6(b) (Rev-3), ln. 5
Col (b): Exh. NG-PP-6(b) (Rev-3), ln. 2
Col (c): Exh. NG-PP-6(b) (Rev-3), ln. 3 +ln. 4
Col (d): Per ACOSS approved in this Order
Col (e): Col (d) - Col (b)
Col (f): See Exhs. NG-PP-6(b) (Rev. 3) at 6-13; NG-PP-8(a) at 32-35; Rerun using the changes approved to the LDAF and GAF
Col (g): IF (Col (a) * 10%) <Col (e) +Col (f), THEN (Col (e) +Col (f) - Col (a) * 10%), ELSE 0
Col (h): if Col (g) <0, THEN Col (d) ELSE 0
Col (i): Col (h) / total Col (h) * total Col (g)
Col (j): Col (d) - Col (g) +Col (i)
Col (k): IF (Col (a) * 10%) <(Col (e) +Col (f) - Col (g)+Col (i)), THEN ((Col (e) +Col (f) - Col (g)+Col (i))- Col (a) * 10%), ELSE 0
Col (l): IF (Col (g) +Col (k) <0, THEN Col (d), ELSE 0
Col (m): Col (l) / total Col (l) * total Col (k)
Col (n): Col (j) - Col (k) +Col (m)
Col (o): IF (2 * ((total Col (d) - total Col (b)) / total Col (b)) * (e) >(n)) THEN (2 * (total Col (d) / total Col (b)) * (e) - (n)), ELSE 0
Col (p): since Col (o) =0, =Col (n)
Col (q): Col (c) +Col (f) +Col (p)
Col (r): (Col (p) - Col (b)) / Col b
Col (s): (Col (q) - Col (a)) / Col a

XVI. ORDER

Accordingly, after due notice, hearing, opportunity for comment and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 1.17; 2.4; 3.13; 4.4; 5.6; and 27 through 57, filed by Boston Gas Company on November 13, 2020, to become effective December 1, 2020, are DISALLOWED; and it is

FURTHER ORDERED: That Boston Gas Company shall file new schedules of rates and charges designed to increase annual gas revenues by $144,857,534; and it is

FURTHER ORDERED: That Boston Gas Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That Boston Gas Company shall comply with all other directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to natural gas consumed on or after October 1, 2021, but, unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

Matthew H. Nelson, Chair

Robert E. Hayden, Commissioner

Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

Name of Respondent	This Report is:		Date of Report		Year of Report
Liberty Utilities (EnergyNorth Natural Gas) Corp.	(1) Original	X	(Mo, Da, Yr)		
	(2) Revised		May 31st 2023		December 31, 2022

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)	Increase or (decrease) (e)
	UTILITY PLANT				
02	Utility Plant (101-106, 114)	17	762,854,824	847,932,381	85,077,557
03	Construction Work in Progress (107)	17	14,655,310	13,240,607	(1,414,703)
04	TOTAL Utility Plant (Enter Total of lines 2 and 3)		777,510,134	861,172,988	83,662,854
05	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115) *	17*	(230,310,206)	(249,582,833)	(19,272,627)
06	Net Utility Plant (Enter total of line 04 less 05)	-	547,199,929	611,590,155	64,390,227
07	Utility Plant Adjustments (116)		0	0	0
08	Gas Stored Underground-Noncurrent (117)		0	0	0
09	OTHER PROPERTY AND INVESTMENTS				
10	Nonutility Property (121)		146,949	146,949	0
11	(Less) Accum. Prov. for Depr. and Amort. (122)		(133,284)	(133,284)	0
12	Investments In Associated Companies (123)		0	0	0
13	Investments In Subsidiary Companies (123.1)		0	0	0
14	(For Cost of Account 123.1	-			
15	Noncurrent Portion of Allowances	-	0	0	0
16	Other Investments (124)		0	0	0
17	Special Funds (125 - 128)		0	0	0
18	Long-Term Portion of Derivative Assets (175)		0	0	0
19	Long-Term Portion of Derviative Assets - Hedges (176)	-	0	0	0
20	TOTAL Other Property and Investments (Total lines 10-13, 15-19)	-	13,665	13,665	0
21	CURRENT AND ACCRUED ASSETS:				
22	Cash (131)	-	(798,267)	(44,979,438)	(44,181,171)
23	Special Deposits (132-134)	-	0	0	0
24	Working Funds (135)	-	0	4,740	4,740
25	Temporary Cash Investments (136)		0	0	0
26	Notes Receivable (141)	-	0	0	0
27	Customer Accounts Receivable (142)		23,259,104	37,291,338	14,032,234
28	Other Accounts Receivable (143)		799,751	1,111,875	312,124
29	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	(2,033,745)	(3,315,899)	(1,282,154)
30	Notes Receivable from Associated Companies (145)	-	0	0	0
31	Accounts Receivable from Assoc. Companies (146)	*	0	1,385,038,758	1,385,038,758
32	Fuel Stock (151)	-	1,469,329	11,629,724	10,160,395
33	Fuel Stock Expenses Undistributed (152)	-	0	0	0
34	Residuals (Elec) and Extracted Products (Gas) (153)	-	0	0	0
35	Plant Materials and Operating Supplies (154)	-	5,910,648	7,232,230	1,321,582
36	Merchandise (155)	-	0	0	0
37	Other Materials and Supplies (156)	-	0	0	0
38	Stores Expense Undistributed (163)	-	0	(608)	(608)
39	Gas Stored Underground - Current (164.1)		4,613,879	0	(4,613,879)
40	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		90,614	155,863	65,248
41	Prepayments (165)		5,520,520	5,609,916	89,396
42	Advances for Gas (166-167)		0	0	0
43	Interest and Dividends Receivable (171)	-	0	0	0
44	Rents Receivable (172)		0	0	0
45	Accrued Utility Revenues (173)		22,868,034	30,763,515	7,895,482
46	Miscellaneous Current and Accrued Assets (174)		967,474	1,101,543	134,069
47	Derivative Instrument Assets (175)		0	0	0
48	(Less) Long-Term Portion of Derivative Instruments Assets (175)	-	0	0	0
49	Derivative Instrument Assets - Hedges (176)	-	0	0	0
50	(Less) Long-Term Portion of Derivative Instruments Assets - Hedges (176)	-	0	0	0
51	TOTAL Current and Accrued Assets (Enter Total of lines 22 thru 50)	-	62,667,341	1,431,643,556	1,368,976,215
52	DEFERRED DEBITS				
53	Unamortized Debt Expense (181)	-	0	(7,315)	(7,315)
54	Extraordinary Property Losses (182.1)		0	0	0
55	Unrecovered Plant and Regulatory Study Costs (182.2)		0	0	0
56	Other Regulatory Assets (182.3)	21	26,415,162	33,264,323	6,849,161
57	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		1,468,165	1,825,934	357,769
58	Clearing Accounts (184)	-	(202,970)	(80,212)	122,757
59	Temporary Facilities (185)	-	0	0	0
60	Miscellaneous Deferred Debits (186)	22	48,758,740	36,204,997	(12,553,743)
61	Def. Losses from Disposition of Utility Plt. (187)	-	0	0	0
62	Research, Devel. and Demonstration Expend. (188)		0	0	0
63	Unamortized Loss on Reacquired Debt (189)	-	0	0	0
64	Accumulated Deferred Income Taxes (190)		0	0	0
65	Unrecovered Purchased Gas Costs (191)	-	0	0	0
66	TOTAL Deferred Debits (Enter Total of lines 53 thru 65)		76,439,097	71,207,727	(5,231,371)
67	TOTAL Assets and other Debits (Enter Total of lines 6, 7, 8, 20, 51, 66)		686,320,032	2,114,455,103	1,428,135,071

* Associated company previously reflected as net now reflected on line 31 page 9 and line 36 on page 10

Attachment D

Name of Respondent	This Report Is:		Date of Report	Year of Report
Liberty Utilities (EnergyNorth Natural Gas	(1) Original	X	(Mo, Da, Yr)	
	(2) Revised		May 31st 2023	December 31, 2022

COMPARATIVE BALANCE SHEET (LIABILITIES AND CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)	Increase or (decrease) (e)
1	PROPRIETARY CAPITAL				
2	Common Stock Issued (201)		124,147,058	124,147,058	0
3	Preferred Stock Issued (204)		0	0	0
4	Capital Stock Subscribed (202, 205)		0	0	0
5	Stock Liability for Conversion (203, 206)		0	0	0
6	Premium on Capital Stock (207)		0	0	0
7	Other Paid-In Capital (208-211)		0	0	0
7B	Accumulated Other Comprehensive Income (219)	**	(4,676,755)	(729,693)	3,947,062
8	Installments Received on Capital Stock (212)		0	0	0
9	(Less) Discount on Capital Stock (213)		0	0	0
10	(Less) Capital Stock Expense (213)		0	0	0
11	Retained Earnings (215, 215.1, 216)	13	102,331,800	130,355,987	28,024,187
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	13		0	0
13	(Less) Reacquired Capital Stock (217)		0	0	0
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 14)	-	221,802,103	253,773,352	31,971,249
15	LONG-TERM DEBT				
16	Bonds (221)	23	0	0	0
17	(Less) Reacquired Bonds (222)	23	0	0	0
18	Advances from Associated Companies (223)	23	159,600,000	159,600,000	0
19	Other Long-Term Debt (224)	23	0	0	0
20	Unamortized Premium on Long-Term Debt (225)		(321,867)	(299,921)	21,945
21	(Less) Unamortized Discount on Long-Term Debt-Debit. (226)		0	0	0
22	(Less) Current Portion of Long-Term Debt		0	0	0
23	TOTAL Long-Term Debt (Enter Total of lines 16 thru 22)	-	159,278,133	159,300,079	21,945
24	OTHER NONCURRENT LIABILITIES				
25	Obligations Under Capital Leases - Noncurrent (227)	-	1,000,146	603,012	(397,134)
26	Accumulated Provision for Property Insurance (228.1)	-	0	0	0
27	Accumulated Provision for Injuries and Damages (228.2)	-	0	0	0
28	Accumulated Provision for Pensions and Benefits (228.3)	-	14,101,762	5,440,137	(8,661,625)
29	Accumulated Miscellaneous Operating Provision (228.4)	-	33,521,828	24,617,774	(8,904,054)
30	Accumulated Provision for Rate Refunds (229)	-	0	0	0
31	TOTAL Other Noncurrent Liabilities (Enter Total of lines 25 thru 29)		48,623,736	30,660,923	(17,962,813)
32	CURRENT AND ACCRUED LIABILITIES				
33	Notes Payable (231)	-	0	0	0
34	Accounts Payable (232)	-	40	3,419,934	3,419,894
35	Notes Payable to Associated Companies (233)	-	0	0	0
36	Accounts Payable to Associated Companies (234) *	44	130,231,905	1,506,811,289	1,376,579,383
37	Customer Deposits (235)	-	3,033,268	3,027,602	(5,667)
38	Taxes Accrued (236) ***	25	(295,825)	0	295,825
39	Interest Accrued (237)	-	0	4,699,353	4,699,353
40	Dividends Declared (238)	-	0	0	0
41	Matured Long-Term Debt (239)	-	0	0	0
42	Matured Interest (240)	-	0	0	0
43	Tax Collections Payable (241)	-	0	0	0
44	Miscellaneous Current and Accrued Liabilities (242) *	*	18,805,269	33,911,365	15,106,096
45	Obligations Under Capital Leases-Current (243)	-	413,679	412,652	(1,028)
46	TOTAL Current and Accrued Liabilities (Enter Total of lines 3	-	152,188,337	1,552,282,194	1,400,093,857
47	DEFERRED CREDITS				
48					
49	Customer Advances for Construction (252)		0	(900)	(900)
50	Accumulated Deferred Investment Tax Credits (255)		0	0	0
51	Deferred Gains from Disposition of Utility Plant (256)		0	0	0
52	Other Deferred Credits (253)	26	0	0	0
53	Other Regulatory Liabilities (254)	27	35,389,237	37,105,422	1,716,185
54	Unamortized Gain on Reacquired Debt (257)		0	0	0
55	Accumulated Deferrred Income Taxes (281-283)		69,038,487	81,334,034	12,295,547
56	TOTAL Deferred Credits (Enter Total of lines 49 thru 55)		104,427,723	118,438,556	14,010,832
57					
58	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 23, 31 46 and 56)		686,320,032	2,114,455,103	1,428,135,071
	* Associated company previously reflected as net now reflected on line 31 page 9 and line 36 on page 10				

Name of Respondent	This Report Is:		Date of Report	Year of Report
Liberty Utilities (EnergyNorth Natural Gas) Corp.	(1) Original	X	(Mo, Da, Yr)	
	(2) Revised		May 31st 2023	December 31, 2022

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others in a similar manner to a utility department manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1,404.2,404.3, 407.1 and 407.2.
4. Use page 16 (Notes to Financial Statement) for important notes regarding the statement of income for any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 16.
8. Enter on page 16 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	Previous Year (d)	Increase or (decrease) (e)
1	UTILITY OPERATING INCOME				
2	Operating Revenues (400)	28	223,746,578	176,027,272	47,719,306
3	Operating Expenses				
4	Operation Expenses (401)	34-39	141,060,323	92,746,852	48,313,471
5	Maintenance Expenses (402)	34-39	3,151,987	4,223,718	(1,071,731)
6	Depreciation Expense (403)		22,051,898	21,403,972	647,926
7	Amort. & Depl. of Utility Plant (404-405)		832,256	1,504,788	(672,532)
8	Amort. of Utility Plant Acq. Adj. (406)		0	0	0
9	Amort of Property Losses, Unrecovered Plant and		0	0	0
	Regulatory Study Costs (407)		0	0	0
10	Amort. of Conversion Expenses (407)		0	0	0
11	Regulatory Debits (407.3)		797,869	671,169	126,701
12	(Less) Regulatory Credits (407.4)		2,186,287	3,087,116	(900,829)
13	Taxes Other Than Income Taxes (408.1)	25	15,750,822	16,715,402	(964,580)
14	Income Taxes - Federal (409.1)	25	246,690	0	246,690
15	- Other (409.1)	25	0	218,670	(218,670)
16	Provision for Deferred Income Taxes (410.1)		10,938,401	6,883,255	4,055,146
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)		0	0	0
18	Investment Tax Credit Adj. - Net (411.4)		0	0	0
19	(Less) Gains from Disp. of Utility Plant (411.6)		0	0	0
20	Losses from Disp. of Utility Plant (411.7)		0	0	0
21	(Less) Gains from Disposition of Allowances (411.8)		0	0	0
22	Losses from Disposition of Allowances (411.9)		0	0	0
23	TOTAL Utility Operating Expenses		197,016,534	147,454,942	49,561,592
	(Enter Total of lines 4 thru 22)				
24	Net Utility Operating Income (Enter Total of		26,730,044	28,572,330	(1,842,286)
	line 2 less 23)				

Name of Respondent	This Report Is:	Date of Report	Year of Report
Liberty Utilities (EnergyNorth Natural Gas) Corp.	(1) Original X (2) Revised	(Mo, Da, Yr) May 31st 2023	December 31, 2022

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	 Previous Year (d)	 Increase or (decrease) (e)
25	Net Utility Operating Income (Carried forward from page 11)		26,730,044	28,572,330	(1,842,286)
26	Other Income and Deductions				
27	Other Income				
28	Nonutility Operating Income				
29	Revenues from Merchandising, Jobbing, and Contract Work (415)		685	1,917	(1,233)
30	(Less) Costs and Exp. of Merch., Job, & Contract Work (416)		0	0	0
31	Revenues From Nonutilty Operations (417)		0	0	0
32	(Less) Expenses of Nonutility Operations (417.1)		(350)	(159)	(191)
33	Nonoperating Rental Income (418)		0	0	0
34	Equity in Earnings of Subsidiary Companies (418.1)		0	0	0
35	Interest and Dividend Income (419)		1,825,658	953,674	871,984
36	Allowance for Other Funds Used During Construction (419.1)		208,904	50,962	157,942
37	Miscellaneous Nonoperating Income (421)		0	0	0
38	Gain on Disposition of Property (421.1)		0	0	0
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		2,034,898	1,006,395	1,028,503
40	Other Income Deductions				
41	Loss on Disposition of Property (421.2)		0	0	0
42	Miscellaneous Amortization (425)		0	0	0
43	Donations (426.1)		74,071	18,049	56,022
44	Life Insurance (426.2)		0	0	0
45	Penalties (426.3)		4,250	162,835	(158,585)
46	Expenditures for Certain Civic, Political and Related Activities (426.4)		33,415	34,498	(1,082)
47	Other Deductions (426.5)		(421,578)	505,124	(926,702)
48	TOTAL Other Income Deductions (Total of lines 41 thru 47)		(309,842)	720,506	(1,030,348)
49	Taxes Applic. to Other Income and Deductions				
50	Taxes Other Than Income Taxes (408.2)		0	0	0
51	Income Taxes - Federal (409.2)		0	0	0
52	Income Taxes - Other (409.2)		0	0	0
53	Provision for Deferred Inc. Taxes (410.2)		0	0	0
54	(Less) Provision for Deferred Income Taxes - Cr. (411.2)		0	0	0
55	Investment Tax Credit Adj. - Net (411.5)		0	0	0
56	(Less) Investment Tax Credits (420)		0	(859,554)	859,554
57	TOTAL Taxes on Other Inc. and Ded. (Total of 50 thru 56)		0	(859,554)	859,554
58	Net Other Income and Deductions (Enter Total of lines 39,48,57)		(2,344,740)	(1,145,443)	1,199,297
59	Interest Charges				
60	Interest on Long-Term Debt (427)		0	0	0
61	Amort. of Debt Disc. and Expense (428)		0	0	0
62	Amortization of Loss on Reaquired Debt (428.1)		0	0	0
63	(Less) Amort. of Premium on Debt-Credit (429)		0	0	0
64	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		0	0	0
65	Interest on Debt to Assoc. Companies (430)	23	744,291	7,106,006	(6,361,715)
66	Other Interest Expense (431)		397,291	237,768	159,523
67	(Less) Allowance for Borrowed Funds Used During Const.- Cr.(432)		(90,986)	(23,067)	(67,919)
68	Net Interest Charges (Enter Total of lines 60 thru 67)		1,050,596	7,320,707	(6,270,111)
69	Income Before Extraordinary Items (Enter Total of lines 25, 58, and 68)		28,024,188	22,397,066	5,627,121
70	Extraordinary Items				
71	Extraordinary Income (434)		0	0	0
72	(Less) Extraordinary Deductions (435)		0	0	0
73	Net Extraordinary Items (Enter Total of line 71 less line 72)		0	0	0
74	Income Taxes - Federal and Other (409.3)		0	0	0
75	Extraordinary Items After Taxes (Enter Total of line 73 less line 74)		0	0	0
76	Net Income (Enter Total of lines 69 and 75)		28,024,188	22,397,066	5,627,121

Name of Respondent	This Report Is: (1) Original (2) Revised	Date of Report (Mo, Da, Yr) Dec. 31, 2022	Year of Report December 31, 2022

SUMMARY OF PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION, AND DEPLETION

Line No.	Item (a)	Total (b)
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified_	788,328,597.36
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	29,369,763.38
7	Experimental Plant Unclassified	
8	Total Utility Plant (Total of lines 3 thru 7)	817,698,360.74
9	Leased to Others	
10	Held for Future Use	2,014,916.53
11	Construction Work in Progress	13,240,607.20
12	Acquisition Adjustments	28,219,103.73
13	Total Utility Plant (Totals of lines 8 thru 12)	861,172,988.20
14	Accumulated Provisions for Depreciation, Amortization & Depletion	(249,582,832.68)
15	Net Utility Plant (Totals of lines 13 less 14)	611,590,155.52
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(249,834,111.98)
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	
21	Amortization of Other Utility Plant	(133,283.70)
22	Total In Service (Totals of lines 18 thru 21)	(249,967,395.68)
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	Total Leased to Others (Totals off lines 24 and 25)	-
27	Held for Future Use	
28	Depreciation	
29	Amortization	
30	Total Held for Future Use (Totals of lines 28 and 29)	-
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	Total Accum Provisions (Should agree with line 14 above) (Total of lines 22, 26, 30, 31, and 32)	(249,967,395.68)

-

NAME OF RESPONDENT:	This Report Is:	Date of Report	Year of Report
Liberty Utilities (EnergyNorth Natural Gas) Corp.	(1) Original X (2) Revised	May 31st 2023	December 31, 2022

GAS OPERATING REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (j) and (k), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold on a per therm basis.
5. If increases or decreases from previous year columns (c), (e) and (g), are not derived from previously reported figures explain any inconsistencies in a footnote.
6. Commercial and Industrial Sales. Account 481 may be classified according to the basis of classifcation (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Dth per year or approximately 800 Dth per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 7, Important Changes During Year, for important new territory added and important rate increases or decreases.

Line No.	Title of Account	OPERATING REVENUES						DEKATHERM OF NATURAL GAS		AVG. NO. OF GAS CUSTOMERS PER MO.	
		Total		BASE		GAS					
		Current Year	Prior Year	Current Year	Prior Year	Current Year	Prior Year	Current Year	Prior Year	Current Year	Prior Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	GAS SERVICE REVENUES * **										
2	480 Residential Sales	$ 113,140,203	$ 88,568,063	$ 53,169,112	$ 50,407,897	$ 59,971,090	$ 38,160,167	5,893,302	5,897,564	85,991	85,638
3	481 Commercial & Industrial Sales										
4	Small (or Comm.) (See Instr.6)	$ 73,516,612	$ 53,249,385	$ 28,062,020	$ 25,195,847	$ 45,454,591	$ 28,053,538	4,586,881	4,459,092	10,656	10,621
5	Large (or Ind.) (See Instr. 6)										
6	482 Other Sales to Public Authorities	$ 9,600	$ 9,600								
7	484 Unbilled Revenue										
8	TOTAL Sales to Ultimate Consumers	$ 186,666,415	$ 141,827,048	$ 81,231,133	$ 75,603,743	$ 105,425,682	$ 66,213,705	10,480,184	10,356,655	96,647	96,259
9	483 Sales for Resale	$ 5,194,220	$ 3,657,912								
10	TOTAL Natural Gas Service Revenues	$ 191,860,635	$ 145,484,960	$ 81,231,133	$ 75,603,743	$ 105,425,682	$ 66,213,705	10,480,184	10,356,655	96,647	96,259
11	Revenues from Manufactured Gas										
12	TOTAL Gas Service Revenues	$ 191,860,635	$ 145,484,960	$ 81,231,133	$ 75,603,743	$ 105,425,682	$ 66,213,705	10,480,184	10,356,655	96,647	96,259
13											
14	485 Intracompany Transfers										
15	487 Forfeited Discounts	$ -	$ -								
16	488 Misc. Service Revenues	$ 1,698,564	$ 1,410,594								
17	489.1 Rev. from Trans. of Gas of Others through Gathering Facilities										
18	489.2 Rev. from Trans. of Gas of Others through Transmission Facilities										
19	489.3 Rev. from Trans. of Gas of Others through Distribution Facilities	$ 12,457,735	$ 15,726,508	$ 12,416,251	$ 15,721,356	$ 41,483	$ 5,152	5,322,960	6,102,457	2,037	2,345
20	489.4 Rev. from Storing Gas of Others										
21	490 Sales of Prod. Ext. from Nat. Gas										
22	491 Rev. from Nat. Gas Proc. by Others	$ -									
23	492 Incidental Gasoline and Oil Sales										
24	493 Rent from Gas Property										
25	494 Interdepartmental Rents										
26	495 Other Gas Revenues	$ 17,729,644	$ 13,405,209								
27	TOTAL Other Operating Revenues	$ 31,885,943	$ 30,542,312	$ 12,416,251	$ 15,721,356	$ 41,483	$ 5,152	5,322,960	6,102,457	2,037	2,345
28	TOTAL Gas Operating Revenues	$ 223,746,578	$ 176,027,272	$ 93,647,384	$ 91,325,100	$ 105,467,165	$ 66,218,857	15,803,144	16,459,112	98,683	98,604
29	(Less) 496 Provision for Rate Refunds										
30	TOTAL Gas Operating Revenues Net of Provision for Refunds	$ 223,746,578	$ 176,027,272	$ 93,647,384	$ 91,325,100	$ 105,467,165	$ 66,218,857	15,803,144	16,459,112	98,683	98,604
31	Dist. Type Sales by States (Inc. Main Line Sales to Resid and Comm Cust	$ 186,666,415	$ 141,827,048	$ 81,231,133	$ 75,603,743	$ 105,425,682	$ 66,213,705	10,480,184	10,356,655	96,647	96,259
32	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-
33	Sales for Resale	$ 5,194,220	$ 3,657,912	$ -	$ -	$ -	$ -	-	-	-	-
34	Other Sales to Pub. Auth. (Local Dist. Only)								-		
35	Unbilled Revenues	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-
36	TOTAL (Same as Line 10, Columns (b) and (d)	$ 191,860,635	$ 145,484,960	$ 81,231,133	$ 75,603,743	$ 105,425,682	$ 66,213,705	10,480,184	10,356,655	96,647	96,259

* Unbilled Revenues reflected in Gas Service Revenue accounts

** Please see page 50 as a suppliment to page28 for gas revenue accounts not included here.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Liberty Utilities (EnergyNorth Natural Gas) Corp.	(1) Original X (2) Revised	May 31st 2023	December 31, 2022

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.		Amount for Current Year (b)	Amount for Previous Year (c)	Increase or (decrease) (d)
238	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**			
239	**Operation**			
240	907 Supervision			
241	908 Customer Assistance Expenses	-	-	
242	909 Informational and Instructional Expenses	92,247	157,330	(65,083)
243	910 Miscellaneous Customer Service and Informational Expenses	-	3,130	(3,130)
244	TOTAL Customer Service and Information Expenses (Lines 240 thru 243)	$92,247	$160,461	($68,214)
245	**7. SALES EXPENSES**			
246	**Operation**			
247	911 Supervision	-	-	-
248	912 Demonstration and Selling Expenses	268,555	416,887	(148,332)
249	913 Advertising Expenses	-	142	(142)
250	916 Miscellaneous Sales Expenses	59,059	80,298	(21,239)
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	$327,614	$497,327	($169,713)
252	**8. ADMINISTRATIVE AND GENERAL EXPENSES**			
253	**Operation**			
254	920 Administrative and General Salaries	15,957,477	5,811,893	10,145,585
255	921 Office Supplies and Expenses	6,280,348	2,935,836	3,344,511
256	(Less) (922) Administrative Expenses Transferred-Cr.	(8,946,904)	(17,243,975)	8,297,071
257	923 Outside Services Employed	5,756,462	7,454,400	(1,697,938)
258	924 Property Insurance	130,114	142,122	(12,009)
259	925 Injuries and Damages	1,423,337	1,151,027	272,311
260	926 Employee Pensions and Benefits	5,238,414	7,527,710	(2,289,297)
261	927 Franchise Requirements		-	-
262	928 Regulatory Commission Expenses	1,090,204	851,941	238,263
263	(Less) (929) Duplicate Charges-Cr.			-
264	930.1 General Advertising Expenses			-
265	930.2 Miscellaneous General Expenses	(3,171,529)	203,873	(3,375,401)
266	931 Rents	119,835	203,286	(83,451)
267	TOTAL Operation (Enter Total of lines 254 thru 266)	23,877,758	9,038,113	14,839,645
268	**Maintenance**			
269	935 Maintenance of General Plant	-	-	-
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	$23,877,758	$9,038,113	$14,839,645
271	TOTAL Gas O. and M. Exp (Lines 97, 177, 201, 229, 237, 244, 251, and 270)	$144,212,310	$96,827,251	$47,385,060

NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to December 31.
2. If the respondent's payroll for the reporting period include any special construction personnel, include such employees on line 3, and and show the number of such special construction in a footnote.
3. The number of employees assignable to the gas department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the gas department from joint functions.

Line No.		Number for Current Year (b)	Number for Previous Year (c)	Increase or (decrease) (d)
1	Total Regular Full-time Employees	299	289	10
2	Total Part-Time and Temporary Employees			
3	Total Employees	299	289	10

Attachment D

Name of Respondent	This Report Is:	Date of Report	Year of Report
Liberty Utilities (EnergyNorth Natural Gas) Corp.	(1) Original X (2) Revised	May 31st 2023	December 31, 2022

GAS OPERATING REVENUES (Account 400) Supplement to Page 28

Line No.	FERC	Account (a)		Amounts from Revenue for Current Year (b)	Amounts from Revenue for Previous Year (c)	Increase or (decrease) (d)
1	480	Residential Sales - Fixed Portion	PG 28	(15,939,140)	(15,786,662)	(152,478)
2	480	Residential Sales - Variable Portion	PG 28	(37,229,973)	(34,621,235)	(2,608,738)
3	480	Residential Sales - Energy Cost	PG 28	(59,971,090)	(38,160,167)	(21,810,923)
4	481	Commercial Sales - Fixed Portion	PG 28	(10,014,069)	(8,881,030)	(1,133,039)
5	481	Commercial Sales - Variable Portion	PG 28	(18,035,651)	(16,304,667)	(1,730,983)
6	481	Commercial Sales - Energy Cost	PG 28	(45,443,257)	(28,049,893)	(17,393,364)
7	481	Industrial Sales - Fixed Portion	PG 28	(10,847)	(9,739)	(1,108)
8	481	Industrial Sales - Variable Portion	PG 28	(1,454)	(411)	(1,043)
9	481	Industrial Sales - Energy Cost	PG 28	(11,335)	(3,645)	(7,689)
10	4893	Metered Sales to Transportation - Fixed	PG 28	(3,012,271)	(3,546,177)	533,907
11	4893	Metered Sales to Transportation - Variable	PG 28	(9,403,981)	(12,175,179)	2,771,198
12	4893	Metered Sales to Transportation - Pass Through Gas	PG 28	(41,483)	(5,152)	(36,331)
13	488	Misc Service revenues	PG 28	(1,698,564)	(1,420,194)	(278,369)
14	495	Other Gas revenues	PG 28	(9,259,437)	(9,553,724)	294,287
15	495	Decoupling Revenue	PG 28	(8,479,807)	(3,851,485)	(4,628,322)
16	483	Sales For Resale	PG 28	(5,194,220)	(3,657,912)	(1,536,308)
17	186+142004	Deferred Working Capital - Winter	PG 9	(62,212)	(22,793)	(39,419)
18	11186000+11142005	Deferred Working Capital - Summer	PG 9	(1,616)	10,307	(11,923)
19	11186000+11174003	Deferred Bad Debt - Winter	PG 9	(132,430)	(414,617)	282,187
20	11186000+11175002	Deferred Bad Debt - Summer	PG 9	(41,779)	593,532	(635,311)
21	11186000+11175003	Deferred Reserves EE	PG 9	(896,113)	(9,426,503)	8,530,389
22	11186000+11182300	R/A Environmental Materials	PG 9	(3,663,628)	(3,166,518)	(497,110)
23	11182300+11174000	Rate Case Recovery	PG 9	(160,787)	(187,166)	26,378
24	11186000+11175004	Deferred RLIAP	PG 9	(486,014)	(2,095,086)	1,609,072
25	11186000+11182300	Deferred Decoupling Asset	PG 9	(307,869)	4,558,886	(4,866,755)
26	11186033+11182314	PTAM	PG 9	(360,758)	-	(360,758)
27						
28						
29						
30						
31	Page number show where full amounts are reflected on this report.					
32						
33						
34						
35						
36						
	TOTAL Operation			(229,859,784)	(186,177,230)	(43,682,555)
						NHPUC Page 50

BEFORE THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 23-039

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

Request for Change in Distribution Rates

AFFIDAVIT OF SEAN P. RILEY

I, Sean P. Riley, being duly sworn, hereby depose and state as follows:

1. My name is Sean P. Riley. I am a Partner at PricewaterhouseCoopers LLP ("PwC") where I am a member of PwC's Utility & Sustainable Energy Practice. My responsibilities include leading PwC's Complex Accounting and Regulatory Solutions Team. In this role, I oversee an experienced team of utility sector specialists that advise PwC clients on complex technical accounting and regulatory matters.

2. I graduated from the University of Vermont in 1990 with a degree in Business / Accounting. I have worked at PwC for over 30 years and am one of the most senior Partners in PwC's Utility & Sustainable Energy Practice. My two roles within PwC include serving as the Global Relationship Partner on some of PwC's largest Utility & Sustainable Energy clients, and leading PwC's Complex Accounting and Regulatory Solutions Team. Previously, I completed a three-year tour as PwC's Utility & Sustainable Energy technical accounting leader in the Accounting Services Group within PwC's National Office. These roles encompass both US GAAP and FERC reporting. I specialize in serving public and privately owned clients - with a particular emphasis on working with regulated electric, gas, and water utilities. Over my career, I have provided leadership and direction around a variety of financial reporting and technical accounting matters, including regulatory accounting, ratemaking, contract analysis, revenue recognition, lease

accounting, cost capitalization, asset impairment, and process / internal control matters. In addition, I have acted as an expert witness in rate case proceedings across the U.S. on a variety of topics.

3. I have reviewed DOE's February 13, 2024, Objection to Motion to Extend Stay of Proceeding and have prepared this affidavit to provide additional details regarding PwC's engagement by Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty ("Liberty" or the "Company") including the expert report that I will produce for the Commission's review.

4. The purpose of my affidavit is to provide the Commission with further information regarding the work that PwC will undertake, particularly in light of statements made in the DOE Objection.

5. I will oversee all of the work on the engagement, sign the expert consulting report, and make myself available to testify before the Commission.

6. Liberty has retained PwC to review certain matters listed below, which include the evaluation of mapping issues within SAP to determine whether there are residual mapping issues related to Liberty's conversion to SAP. I have extensive experience working with utilities that utilize an SAP based environment. Many of our utility clients use SAP.

7. In addition, we will leverage professionals within our utility practice that are specialists in relation to IT processes, controls, and systems conversions for SAP environments. This team will perform a review of the data conversion from the legacy Great Plains system to SAP (i.e., understand the Company's process for assessing accuracy and completeness of the conversion of data, including adjustments recorded as part of the system reconciliation process).

8. The PwC assessment will, in fact, examine the 2022 financial data used as the basis for the rate filing by comparing the Company's most current version of the revenue requirement

filing which incorporates the proposed Staff audit adjustments and the Company's identified adjustments and working back to the Company's 2022 trial balance used as the basis for the initial rate filing. We will also perform procedures starting from the amounts recorded in the 2022 financial statements forward to the initial rate filing and subsequently to the November 27, 2023 updated filing and the Company's additional identified adjustments as communicated in the January 4, 2024 hearing. In addition, we will trace such amounts to the reported regulatory accounts (from the Form 1 report) and / or rely on the Staff's audit report where such procedures have already been performed.

9. PwC has been engaged to "confirm … that the 2022 financial information is, in their opinion, reliable for rate setting." PwC's work will not be a rubber stamp of Liberty's rate filing. PwC will determine whether the adjustments Liberty made to its 2022 financial information to prepare the proposed revenue requirement in this rate proceeding are accurate and reliable for rate setting.

10. To perform this assessment, PwC will assess Liberty's financial records supporting the basis for the Company's proposed revenue requirements described herein and produce an "expert consultant report". While this assessment will be extremely thorough and reliable, it cannot be labelled an "audit" of the 2022 books. The term "audit," when used by an accounting firm (including PwC), has a very specific meaning. According to the American Institute of Certified Public Accountants, AU-C Section 200.04, "The purpose of an audit is to provide financial statement users with an opinion by the auditor on whether the financial statements are presented fairly, in all material respects, in accordance with an applicable financial reporting framework, which enhances the degree of confidence that intended users can place in the financial statements.". Further, the AICPA Code of Conduct would preclude me from testifying before the Commission

if an "audit" report were produced. To allow me to testify before the Commission, provide my opinion, and respond to questions from the Commission and cross-examination from parties to this proceeding, Liberty retained PwC to produce an expert consulting report. The expert consulting report is subject to the same professional and ethical guidelines as an audit report.

11. During this engagement, PwC will:

- Review and analyze information and documentation provided by Liberty, including:
  - Liberty's Rate Proceeding to gain an understanding of the various adjustments included in the Rate Proceeding,
  - The DOE's Audit Report on the Liberty Rate Proceeding,
  - Liberty's policies, procedures and related controls for regulatory filings, including Liberty's reconciliation process, and
  - Liberty's controls and reconciliation procedures for assessing the accuracy / completeness of the data conversion to Liberty's new Enterprise Resource Planning system in Q4 2022.
- Conduct interviews and/or process walk throughs with relevant Liberty stakeholders, as necessary, to obtain information about the procedures performed by the Company.
- Review 2022 year-end externally audited financial statements, 2022 FERC Form 1, 2022 adjusted test year that formed the basis of the revenue requirement, known and measurable adjustments to the test year, November 27, 2023, adjustments and adjustments identified by the Company after the November 27, 2023 filing.
- Perform a root cause analysis to gain an understanding of, where possible, the potential causes of the identified potential gaps/variances, and the magnitude and nature of the adjustments.
- Based on the above, prepare an expert consulting report which will include the scope and approach, findings, observations, assumptions and limitations related to the procedures performed and conclusions on whether the Company's basis for asserting such data is reliable is accurate.

12. Performance of this work will be subject to professional and ethical guidelines in line with those set forth in the American Institute of Certified Public Accountants ("AICPA") Code of Conduct. These professional and ethical guidelines ensure that the work performed by PwC is impartial and independent. I have also agreed to provide testimony to the Commission, under oath, regarding this engagement and production of the expert consulting report.

13. It is a common practice for an entity to request that PwC produce an expert consulting report where testimony in a regulatory proceeding is anticipated or required.

14. Liberty retained PwC to complete this work on an expedited basis. To meet the deadlines established by Liberty, PwC has committed the resources necessary to perform the promised work. PwC is a worldwide consulting firm with over 325,000 employees in 152 countries and 688 locations around the world. In the United States, there are over 75,000 professionals and 4,000 partners. As the leader of PwC's Complex Accounting and Regulatory Solutions Team, a team that has substantial experience with SAP and utility ratemaking, I have sufficient PwC resources to complete the work within the proposed timeline. PwC has also advised Liberty that the proposed timeline cannot be met without Liberty's full cooperation.

Sean P. Riley

SEAN P. RILEY