STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

March 22, 2018 - 10:10 a.m.
Concord, New Hampshire

DAY 4
Morning Session ONLY

RE: **DG 17-048**
LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. d/b/a LIBERTY UTILITIES: Request for Change in Rates. ***(Hearing on the merits)***

PRESENT: Chairman Martin P. Honigberg, Presiding
Commissioner Kathryn M. Bailey
Commissioner Michael S. Giaimo

Sandy Deno, Clerk

APPEARANCES: **Reptg. Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities:**
Michael J. Sheehan, Esq.

Reptg. Residential Ratepayers:
D. Maurice Kreis, Esq., Consumer Adv.
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Reptg. PUC Staff:
Paul B. Dexter, Esq.
Alexander F. Speidel, Esq.
Stephen Frink, Dir./Gas & Water Div.
Al-Azad Iqbal, Gas & Water Division

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

I N D E X

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E X H I B I T S

P R O C E E D I N G

CHAIRMAN HONIGBERG: We're here to continue the rate case, hearing on the merits, for EnergyNorth Natural Gas. I think this is Day 3.

What are we doing this morning, gentlemen?

CMSR. BAILEY: Day 4.

CHAIRMAN HONIGBERG: Day 4? Oh. Thank you. I'm going to run out of fingers soon.

MR. SHEEHAN: It only seems like seven.

MR. DEXTER: Good morning, Mr. Chairman. What we have on the schedule today is the Staff's presentation of the witness Mr. Frink's testimony.

There's been some scheduling changes due to weather-related travel problems. So, I could go through what counsel and I discussed for the rest of the week, or we can just do it day-by-day.

But, today, due to the changes, all we have is Mr. Frink.

CHAIRMAN HONIGBERG: All decisions are final until changed. So, you can tell us what the plan is, which probably would be helpful for preparation for tomorrow.

MR. DEXTER: Sure. The plan tomorrow is to proceed with the OCA and Company's decoupling witnesses, Mr. Therrien and Dr. Johnson. And followed by the testimony of Mr. Iqbal from the Staff, on the issues of training and decoupling.

And then, on Monday, the Company's depreciation witness is scheduled to arrive. So, he would testify first, Mr. Normand, followed by Mr. Iqbal, on the issue of depreciation.

And that would complete all the witnesses.

CHAIRMAN HONIGBERG: Okay. Mr. Sheehan.

MR. SHEEHAN: With the caveat that we do have a right to rebuttal, if appropriate. And the thinking now is that Mr. Mullen might do a half hour clean-up of things that we think need to be responded to.

CHAIRMAN HONIGBERG: Okay. Mr. Frink, you ready to go?

MR. FRINK: Ready to go.

CHAIRMAN HONIGBERG: While Mr. Frink is moving in that direction, there was a question outstanding yesterday from Mr. Hall and --

MR. CLARK: Mr. Clark.

CHAIRMAN HONIGBERG: -- Mr. Clark. And I have now forgotten the question, but it was something Mr. Hall was going to consult with.

Do we know what the result of that was?

MR. SHEEHAN: Yes.

CHAIRMAN HONIGBERG: Off the record.

[Brief off-the-record discussion ensued.]

CHAIRMAN HONIGBERG: Go ahead.

MR. HALL: The question was "whether the Keene average consumption in the typical bill comparisons on attachment -- on the attachment to the Settlement were based on Keene specific data?" And the answer is "Yes, it was."

CHAIRMAN HONIGBERG: Now that you've refreshed my memory, it also went a little beyond that, I think. And the question was "whether what was listed as "residential" was residential heating or all residential?"

MR. HALL: It was separated into two pieces. There was a residential non-heating class and a residential heating class. The separation was done based on analyzing customers' consumption amounts individually and putting them in one class or the other.

CHAIRMAN HONIGBERG: And, so, is it fair then to conclude, in your view, that people in Keene use less than the rest -- than customers in the rest of the system, residential customers in the rest of the system?

MR. HALL: Yes.

CHAIRMAN HONIGBERG: Okay. Thank you, Mr. Hall, and Mr. Mullen.

Mr. Patnaude, would you swear in the witness please.

(Whereupon ***Stephen P. Frink*** was

duly sworn by the Court Reporter.)

CHAIRMAN HONIGBERG: Mr. Dexter.

MR. DEXTER: Thank you, Mr. Chairman.

STEPHEN P. FRINK, SWORN

DIRECT EXAMINATION

BY MR. DEXTER:

Q Would you identify yourself for the record please.

A Stephen Frink. I'm the Director of the Gas & Water Division at the Commission.

Q Thank you. Mr. Frink, did you file prefiled direct testimony in this proceeding on November 30th, 2017?

A I did.

Q Do you have that document before you?

A I do.

MR. DEXTER: This document I don't think has been marked for identification yet. In the initial list, I believe it was inadvertently left off.

So, I would ask that this be marked as "Exhibit Number 56"?

CHAIRMAN HONIGBERG: Okay.

(The document, as described, was herewith marked as **Exhibit 56** for identification.)

BY MR. DEXTER:

Q Mr. Frink, do you have any corrections you'd like to make to the testimony that was filed on November 30th?

A I do have one correction, or perhaps it's more supplemental. But the Staff has agreed with the return and capital structure that's been proposed in the Settlement Agreement. And, so, the iNATGAS recommendation -- recommended adjustment has been updated to reflect that capital structure and that capital cost. And, so, in my original testimony, I recommended a 379,264 reduction to the revenue requirement associated with the iNATGAS. And that number, due to a return on equity that's now 9.4, rather than 8.5, is now a reduction of 396,576.

Q And you've prepared a supplemental schedule to reflect that update, is that not correct?

A That's correct.

Q Can you point the Commission to the schedule in the original filing, before I pass out the new one?

I believe it's Bates Page 078 of your original testimony.

A Thank you. That is correct. Page 78, or Bates Page 078.

MR. DEXTER: So, what we're distributing now is an updated -- what we're distributing now is an updated version of that schedule.

[Mr. Iqbal distributing documents.]

MR. DEXTER: And I ask that that be marked as "Exhibit 57"?

CHAIRMAN HONIGBERG: Okay.

(The document, as described, was herewith marked as **Exhibit 57** for identification.)

BY MR. DEXTER:

Q And could you just briefly point out the difference, the update, where the update impacts Exhibit 57 versus the original schedule.

A If you look at Line -- down at the bottom of the page is the capital structure, and, on the original testimony, it's the "Staff Proposed Capital Structure and Rate of Return". If you look at the updated supplemental revised, the exhibit here, you'll see that it's the "Settlement Capital Structure".

And as a result of increasing the return, that increased the revenue requirement. And, so, consequently, there's a slight increase that, as I already stated, was basically 380,000, and now it's about 400,000.

Q Okay. And if I go to Line 44 on the new exhibit, Exhibit 57, there's a reference to "Settlement" there. That refers to the Settlement between the Consumer Advocate's Office and Liberty Utilities, correct?

A Yes, it does.

Q Okay. So, having made that update, if I were to ask you the questions contained in your original testimony, would your answers be the same as those contained therein?

A Yes, they would.

Q And do you adopt those answers as your sworn testimony in this proceeding?

A I do.

Q Thank you. Mr. Frink, you've been in attendance at the various hearings that have taken place in this proceeding, correct?
A That's correct.
Q And prior to that, did you have a chance to review the rebuttal testimony that was submitted by Mr. Hall and Mr. Clark on the issue of iNATGAS?
A I have.
Q Do you have any remarks you'd like to make concerning the rebuttal testimony of those witnesses concerning iNATGAS?
A I do have a number of responses to the testimony, the rebuttal testimony that the Company filed as it relates to iNATGAS.

First, I'd like to start by the rebuttal testimony points out that Staff incorrectly interpreted the contract between the Company and iNATGAS. And in my testimony, I have an attachment of the Staff report filed in DG 14-091. And on Bates Page 070 of my testimony, you can read where it says, the last paragraph, "the 'must take' provision is only in effect for five years".

Clearly, that's not the case, as pointed out by the Company.

Q Did that -- had you known that the take-or-pay provision was in effect for fifteen years -- for the full length of the contract, fifteen years, rather than the five years, would that have changed your recommendation in DG 14-091?

A It would not have changed my recommendation. The Staff report, again, contained in my -- as an attachment in my testimony, explains that Staff's greatest concern was that the iNATGAS may not -- may actually fail. And we were concerned about it, that the real risk wasn't the take-or-pay, if iNATGAS, it was -- the business plan failed and they were bankrupt, then it didn't matter how many years you had on the take-or-pay requirement, they wouldn't be paying it. And that was the purpose behind the escrow.

And again, I'll refer you to the report from 14-091. And if you turn to Bates Page 073 of my testimony, in that report it reads, again, this is about our concerns regarding iNATGAS: "iNATGAS is a new entity with no customers, three employees, very limited assets, and will be competing with the Clean Energy CNG station located within a mile of Concord" -- "of the Concord facility, along with other stations located in Vermont and Maine."

And if you had flip another page to Bates Page 074, it goes on to express Staff's concerns regarding the risk: "If no revenues are realized through the special contract, ratepayers may absorb the entire cost of the project."

Staff stated that the take-or-pay and other guarantees did not offer sufficient ratepayer protection. So, all along Staff's primary concern was the risk to ratepayers.

For the Company, if the project turned out not to be profitable, and it was allowed in rate base, there's no risk to the Company. The only risk to the Company is that the Commission may find that it wasn't -- the project was imprudent or make some allowance for its lack of profitability, which is what Staff has proposed here.

And again, it goes back to, we were concerned about the ratepayer risk. We were concerned that Liberty was proposing a $2.2 million investment. INATGAS was approximately a million. So, to balance the risk, we suggested an escrow tied to actual sales.

And as it turned out, the actual sales revenues for the first three years have been zero. And, so, I think Staff's scenario on which its decision was based, the high risk scenario, is probably a lot closer to the way things have played out than certainly the Liberty worst-case scenario, which was the take-or-pay requirements.

But, anyway, that's, to make a long story short, Staff was concerned about the risk to ratepayers. Staff presented a scenario in which iNATGAS was unable to meet their obligations under the contract. And that is why Staff signed the -- was willing to sign onto a settlement agreement, or, actually, Staff made that proposal, and Liberty accepted it, and iNATGAS and Liberty entered into a escrow agreement.

Q But you do now agree with the Company that the take-or-pay provisions are in effect for the 15-year life of the contract, correct?

A Yes. The take-or-pay provisions, as explained by the Company, the iNATGAS started receiving service December 2016, and that triggered the contract. As the Company explained, there's one rollover in the contract, to where iNATGAS -- they had their first trailer fill on December 2017. So, they would have been required to pay the take-or-pay -- meet the take-or-pay requirements, if they hadn't rolled it over. Instead, they rolled it over. So, in this coming year, this year, actually, 2018, they -- iNATGAS will be responsible to pay for sales -- minimum sales of 600,000 decatherms.

And I would like to say, I do have a concern with that. We heard testimony that iNATGAS now has a customer, and that the customer used 125,000 decatherms for the first -- for December, January, February, the majority of that coming in January. I guess there was about 20,000 in December, and then close to 100,000 in January, which is hardly surprising, given the extreme cold we had in January, and the increase in prices, and the tight market during that period, that you'd expect a pretty decent load under those circumstances. Whether they will actually achieve the 600,000 for the year, that that remains to be seen.

But I would like to say, I don't share the Company's confidence that iNATGAS is going to realize sales that exceed the minimum take-or-pays, given the rollover.

Q And that's -- the 600,000 that you mentioned is the minimum take-or-pay requirements, taking into account the rollover. Is that what your testimony is?

A Yes, for this year.

Q Mr. Frink, do you recall a discussion in the Hall/Clark rebuttal testimony filed back in January about whether or not AFUDC should be considered in evaluating the cost-effectiveness of the projects?

A Yes.

Q Of this project?

A I had a fair amount of discussion on AFUDC. And I would agree with the Company that overheads do not belong in the analysis. And, in fact, --

Q Let me stop you there.

A Okay.

Q When you say "overheads", are you including AFUDC or are you talking about only overheads?

A I am not. In the rebuttal testimony, on the Clark/Hall rebuttal testimony, on Bates Page 067, it states that Staff made -- has mischaracterized those costs. The cost total of "4,815,594 is the fully loaded cost of the project, which includes the direct costs plus AFUDC, Overheads, and Burdens." And I do not agree with that. As a matter of fact, one of the data responses, Exhibit 46, which is the -- was prepared by Mr. Clark, in his DCF analysis showing the updated costs, final costs of the project, specifically states that the project costs do not include burdens.

And if you look at the Consulting -- the Liberty Consulting report, which is attached to my testimony, on Bates Page 097, it states that

"Management recorded a final iNATGAS CNG project cost of $4,971,030." So, the iNATGAS that was added to rate base is actually about $5 million. But the cost used in the updated DCF analysis removes $155,635 of burdens.

And -- okay.

Q I'm sorry. And just so that everyone can follow along, you mentioned "Exhibit 46". Am I correct that that was Mr. Clark's response to Staff Tech 3-12?

A Yes.

Q And you're looking at the Bates Page 002 of that exhibit, up in the upper right-hand corner, where it states that this analysis does not include burdens?

A Actually, I don't have that with me. So, I'll take your word for it.

Q I'll be happy to show it to you.

MR. DEXTER: May I approach the witness?

CHAIRMAN HONIGBERG: Sure.

[Atty. Dexter handing document to the witness.]

BY THE WITNESS:

A And that is the Company's response to Staff Tech 3-12, and the respondent was William Clark. And the date of the response is 11/15/17.

BY MR. DEXTER:

Q And up in the upper left-hand corner of Page 2, it also indicates that AFUDC is included in this analysis?

A Yes. On Line 10, it specifically states "AFUDC - Actual $435,510.

Q And you understand that the Company disagrees that AFUDC should be included in the analysis, and that they were just responding to the question as you asked it?

A That is their position, yes.

Q Okay. But I'm just trying to -- we're trying to separate out --

A Right. Yes.

Q -- what's in what analysis.

A Right.

Q Okay. All right. Now, having done that, do you have an opinion as to whether or not AFUDC should be included in this analysis to properly evaluate the cost/benefit of the iNATGAS project?

A It absolutely should be. I don't -- Mr. Hall seemed to think we're moving the goal post, and that there's a revenue test for line extension requests that has a particular criteria that they applied in this analysis. And when you're doing a special contract, that -- the Line Extension Policy criteria is for line extension policies. You aren't bound by that when you do an analysis for a special contract.

That said, I think the Line Extension Policy should be changed to include AFUDC. That is an incremental cost that is directly tied to a particular project. I don't think direct costs should be included, because if they were, those costs could be paid by ratepayers regardless of whether iNATGAS is built. It's either going to be allocated to another capital project or recovered through the Company's O&M.

Q Let me interrupt you there for a second, because I think you said you "don't think direct costs should be included".

A I do not think --

Q Did you mean to say "indirect"?
A Oh, I'm sorry. Right. I meant "indirect and overheads".
Q And by "indirect costs", you mean not AFUDC, but you do mean "overheads"?
A Right. I do mean "overheads". Thank you for that correction. AFUDC is, basically, the costs associated to finance the construction project, there's a real cost, and that should be -- that's an incremental cost that should be reflected in the analysis.

And I will say that the -- since Liberty acquired EnergyNorth, that Line Extension Policy, the criteria, financial criteria used to evaluate, to determine if a line extension will be done, has changed three times, or there have been three different criteria. We're always looking to improve. We're always, if we make adjustments and find that it could be tweaked and improved, we do that.

And I'm not proposing it in this rate case, but I do think that's something we should look at and consider. And it should definitely be done in an analysis outside of a line extension -- outside of a line extension policy.

Q In your view, has the significance of AFUDC in the iNATGAS analysis increased over the course of the project?

A Absolutely.

Q And if so, why?

A If you look at Exhibit 51, which was marked for exhibit and filed today, it shows what the AFUDC would have been if the project had it been built on budget and put into service on time. And that cost is "$51,307.08. That is less than, in the original analysis, there was $180,000 for contingency, it's far less than that. So, to say not including AFUDC did not have a major influence in this, in the decision. If you had included AFUDC, if they had done projected AFUDC for the project, it would have been 51,000. So, it's not really material.

Q Thank you. Now, concerning the various costs --

CMSR. BAILEY: Mr. Clark -- I'm sorry, Mr. Dexter, before you go on, --

CHAIRMAN HONIGBERG: He's Mr. Clark now.

CMSR. BAILEY: Sorry.

CHAIRMAN HONIGBERG: Look what I started.

CMSR. BAILEY: Before you go on, could you have Mr. Frink repeat the testimony about the indirect costs that --

MR. DEXTER: Sure.

CMSR. BAILEY: I got the AFUDC. But I'm not sure about the rest of the point that you were trying to make.

WITNESS FRINK: Let me --

CMSR. BAILEY: Could you please repeat that.

MR. DEXTER: Sure.

BY MR. DEXTER:

Q So, Mr. Clark, earlier you were discussing --

CMSR. BAILEY: He called him "Mr. Clark".

[Laughter.]

MR. DEXTER: Oh, I'm sorry.

CHAIRMAN HONIGBERG: Oh, man.

MR. DEXTER: We're all "Mr. Clark".

BY MR. DEXTER:

Q So, Mr. Frink, earlier we were having a discussion about AFUDC, overheads, burdens, direct costs, and indirect costs. So, what I'd like you to do, just to make things crystal clear, is indicate what you mean by each of those terms, and indicate which you think should be in the analysis of the iNAT facility and which you think should not?

A Okay. First, AFUDC. That is the cost associated with financing the project. I would equate it to a construction loan. That cost is added to the project when you put it in service, and it's capitalized. So, that is an incremental cost. That is an added cost to a project. The Company actually has financing that, you know, they have to finance these projects. So, that's an added cost.

The indirect gas costs, which would be the overheads and the burdens, those are costs that -- so, burdens would be payroll costs that -- so, you have people overseeing -- supervisors that are overseeing the project, you have engineers that are involved in the project. Their vacancy time, their benefits, their -- the employee-related costs that all get put in a bucket and gets allocated to capital projects. So, if an employee works on this project, he spent 10 percent of his time on it in that year, then 10 percent of his salary gets charged to it. And then you take these burdens, which are all the personnel costs associated with that, and that gets added to his direct time. So, that's what the indirect cost is.

So, whether he works on this project or not, his salary and his benefits are all reflected in the revenue requirement, and they're going to get charged to ratepayers, regardless of whether you build this particular project.

So, if he hadn't spent his 10 percent there, and spent 30 percent on some other project, then 30 percent would have gotten allocated to that project, and the rest would have been through O&M. So, that's what indirect costs are.

Q So, barring some drastic change in the capital budgeting, capital expenditures of the Company, I think what I'm gathering is that the overhead burdens, you're actually -- they're the same thing?

A Yes.

Q You're using those synonymously?

A Well, the overhead, it's -- with Liberty, it's a little more complicated. The burdens are the personnel costs. I believe the overheads are tied to costs that come down from the service company or from Oakville. So, I think those are -- I think there is a distinction there. But --

Q But, barring some drastic change in the level of capital spending, those overheads and burdens are not avoidable, they would just be spread to other projects. Is that your understanding?

A That's my understanding, yes.

MR. DEXTER: Okay. Does that help, Commissioner?

CMSR. BAILEY: Thank you.

BY MR. DEXTER:

Q So, Mr. Frink, why don't we leave that issue for a moment. And there's been a fair amount of testimony on the difference between the projected cost of the iNATGAS facility back in 2014, at about 2.2 million, and the final cost, which is around 4.5 to 5 million, depending on whether or not you include AFUDCs.

Could you comment on the -- I'm sorry. Do you have any comment on the reasons that Liberty Utilities gave for the overhead -- for the overruns, for those variances, those budget differences?

A I certainly do. Now, when Liberty filed for approval of the iNATGAS project, they requested an expedited schedule in an effort to begin service that November. Rushing to get the project in service may have contributed to the inaccurate cost estimates. Liberty did not have contractor bids, did not realize what the Company requirements would be, and apparently didn't realize that a full build-out would produce savings that would justify not waiting to see if the iNATGAS load requirement would materialize and would require the additional capacity.

Liberty should have foreseen and considered these costs and savings in its initial analysis or delayed the filing until it had a better understanding of the potential costs and risks.

Q And do you recall the date on which the Company filed for approval of the special contract?

A April 2014.

Q And do you recall what timeframe they requested approval of that?

A I believe it was May.

Q And would you agree that the Commission order approving the iNATGAS special contract was issued in July of 2014?

A Yes.

Q And after a hearing held in the middle of June in 2014?

A Yes.

Q Okay. So, Mr. Frink, I'd like you, with that background, to explain Staff's position in this case with respect to the iNATGAS facility. In other words, what is it you're actually recommending in the context of this rate case?

And I think it would probably be helpful if you looked at Exhibit 57 to explain that.

A Oh. You're right. Thank you. So, the Company prepared a discounted cash flow analysis as part of its request for approval of the special contract with iNATGAS. And they did a -- that analysis reflected what the costs would be, expected costs, and what the expected revenues would be. And the associated revenue requirement, what customers would be -- how that would impact rates going forward.

And, so, when they did that analysis, it shows what the revenue requirement is by year-to-year over the course of the -- over the life of the contract, and that was expected to begin in 2014.

So, the contract, as previously stated, the iNATGAS service commenced in December of 2016. And so that's when the contract began.

And, so, for the purposes of this analysis, I've looked at what the revenue requirement would have been in the first year of service under the actual -- under the projected costs that they -- on which the decision to enter the contract was certainly, in part, based on, and calculated what that revenue requirement is. So, if you look at the -- on Exhibit 57, it says "Projected", this is near the top, right below the title, "Projected 1", that's year 1. And calendar year, even though in the filing, the 14-091 filing, the first year was 2014; as we know, that didn't happen. So, I'm saying "2017" for the first year.

And you can see the projected costs were 2.2 million. You can see the associated rate elements that would go into calculating the revenue requirement. And then you would see that the annual revenue requirement at the end of the first year would have been $348,000.

Q And that's down on Line 38 of Exhibit 57?

A That's Line 38. Yes. And then, under the take-or-pay requirement, which is $192,600 -- well, that's not entirely take-or-pay. There's a piece that is related to the Lease Agreement, which is, I will say, approximately 10 percent, I guess. So, those revenues are in here. But the revenue at the minimum take-or-pay I put down as "192,600". And it leaves a revenue deficiency which would satisfy -- the revenue requirement would be satisfied by $192,600 of revenue expected to be realized under the take-or-pay and Lease Agreement. So, that means there's a revenue deficiency of $155,447. That's what was anticipated when the -- in year one of operations, when Liberty made its request for approval of the special contract. Now, --

Q And just before that, if that had happened, I think as I understand what you're saying, is that $155,000 revenue deficiency would essentially be spread to all the other customers of EnergyNorth? Is that how I read this schedule?

A That's correct.

Q Through the course of the rate case revenue deficiency calculation?

A Yes.

Q Okay.

A And, so, the project actually wound up costing, direct costs and AFUDC, and as you can see, the contingency was not quite enough in the original estimate, $180,000, the actual AFUDC, which I left in my analysis, as I reflected in the contingency, was $435,510. But the other costs as well as you can see, and this was -- the Company went through this during cross: Compressors are 1.1; piping, meters, *etcetera*, 3 million; land, 200,000; and AFUDC 435,000, for a cost of 4.8 million.

Again, you look at the rate elements, look at what the revenue requirement is, would have been, if those had been the numbers that had been submitted at the time of the request, if Liberty had forecasted these costs on the start date, then this is what the revenue requirement would been in year one. Down on Line 38, it would have been $744,623. So, now you look at what the revenue is under the iNATGAS Lease Agreement and take-or-pay requirements, and that revenue would offset that $750,000 revenue requirement, and you'd have a revenue deficiency of 552,000.23 -- $23 **[**$552,023**]**.

Q And so, just to ask that same question with regard to that number that you just read on Line 42, as the case was proposed by Liberty --

the rate case was proposed by Liberty, that $552,000 would flow through to -- would be charged to all the other EnergyNorth customers, if no adjustments were made by Staff in this case. Is that right?

A Yes. That's correct.

Q And, in fact, might it even be higher, because the take-or-pay revenues were deferred?

A Well, actually, I'm thinking about this. This, let's see, the difference is 400,000, yes. The -- excuse me?

Q My question was, and, in fact, might that revenue deficiency of 552,000 might even be higher, because the 192,600, on Line 40, wasn't actually received this year because of this deferral of the take-or-pay that we talked about earlier?

A That's true. But the Company did make a adjustment to their revenues to reflect the take-or-pay requirements.

Q Okay.

A That they did actually receive that -- well, customers aren't being charged for it.

Q Okay.

A The Company did not receive the revenue, but they did not pass that onto ratepayers through their proposed revenue requirement.

Q Very good then. So, I interrupted you. You were about to get to the calculation of your adjustment in this case. So, why don't you proceed with that.

A Right. So, if you take the expected revenue requirement that was based on actual costs of 155, and I would also like to say that 155 -- that that revenue requirement is at the Settlement Agreement cost of capital rate of return. So, originally, I believe, in the initial -- what was filed in 14-091 was the return on equity at that time, the capital structure at that time. But this reflects what the parties have agreed to for a -- should be a -- the capital structure and the rate of return.

So, anyway, the "155,447", based on the agreed capital rate of return, and the -- that expected under the projected costs is then subtracted from the $552,023 that is the actual revenue requirement shortfall that results from the -- from the actual cost of the project, so the overruns and so forth. And it doesn't really -- in some ways it reflects the delay, because the AFUDC obviously would have been a lot less if the project hadn't taken -- had only taken a half year to complete versus two and a half years. So, there is a -- the delay is somewhat reflected in here.

I would say that, if the project had gone into service on time, going back to the original projections, the revenue requirement from -- in each year it actually goes down, so -- due to depreciation and other factors, over time the revenue requirement drops. So, if had gone into effect in year -- in 2014, as originally intended and expected, then we'd be looking at a much lower revenue requirement if it had -- if you go back to the initial analysis and you look at year 3 revenue requirement, I think it's like a deficiency of 25,000.

So, I haven't made any allowance for that. I've simply said, okay, this is the first year. This is what would have been expected under the actual projected costs. And this is what it is as a result of the overspending.

Q Now, from a rate case practical point of view, please distinguish the treatment that you've recommended, from maybe a more straightforward approach, which would have been a rate base exclusion on basis of the cost increases that you talked about.

A Right. This -- we're not saying that this isn't used and useful. We are saying that Staff supported the recommended approval of a special contract. Admittedly, if we had known what the real costs were going to be, our recommendation may have been different. But we signed onto the -- we signed onto what the expected impact was going to be. And, so, what we're looking at here is, okay, for whatever reason, the actual costs are well above what was expected. The revenue deficiency associated with this project is, you know, three or four times what was expected. We are making an adjustment at this time, because that -- we don't feel ratepayers should be responsible for these overruns and be impacted by this. Just like the Company made an adjustment to the revenues, because they're expecting revenues from iNATGAS.

But these -- this project, this $4.8 million, almost 5 million that went into rate base, is in rate base. It will be in rate base when Liberty comes back for their next rate case. And barring a adjustment that is recommended and approved by the Commission, they'll get full recovery of those costs as part of their next rate case.

And it may well be that, by the next rate case, iNATGAS achieves the sales they have expected, and maybe it will be profitable. Obviously, Staff will be following this. If the project continues to have a very negative impact on ratepayers, well in excess of what was anticipated, then maybe -- and, so, in the future rate case, Staff will raise the issue again.

But, as it stands right now, Staff is just saying, as part of this rate case, there should be allowance made for the fact that this project was either misrepresented, miscalculated, mismanaged, whatever, there is a -- basically, a $5 million project in place of what was expected to be a two and a half million dollar project, and ratepayers shouldn't be responsible for that, that difference, at this time.

And again, if it proves to be profitable, great. I'll applaud the Company, and I certainly won't be looking for a disallowance. But that's not where things stand right now.

Q Thank you, Mr. Frink. That's all I have on iNATGAS.

I'd like to talk for a moment about the portion of the Hall/Clark rebuttal that dealt with the proposal to consolidate the Keene Division into the rates of EnergyNorth.

A But, before we move on, --

Q Before we move on, --

A -- I do have one more.

Q -- you have one more issue that I skipped. You're right.

A Yes.

Q Back on the iNATGAS for a moment. In the rebuttal testimony, there was a mention of --

in the rebuttal testimony of Mr. Hall and Mr. Clark, there was mention of benefits that would accrue from capacity releases that would be made in connection with this facility. Can you explain those capacity releases and indicate whether or not you agree that those capacity releases will benefit EnergyNorth's firm customers?

A If the Company has excess capacity, then this is a benefit to ratepayers. So, they hold capacity to serve their -- all their customers in total. And to the extent they have more customers taking that capacity, then that cost is spread between customers. The Company has filed, as a integrated resource plan and the Granite Bridge Project, they're stating that they have a revenue deficiency.

Q Do you mean a "capacity deficiency"?

A I'm sorry, yes. A capacity deficiency, thank you. So, to the extent this load on iNATGAS requires the Company to go out and acquire new capacity, that new capacity can be and typically is much higher than the existing capacity. So, the capacity on Tennessee

Pipeline, for instance, lines that have been in place for a long time, they were installed at less cost, they have been depreciated, they're generally a lot cheaper than a new capacity. And that is certainly the case -- appears to be case based on the current filings.

And, so, if they -- if this additional load is causing the Company to have to go out and acquire additional capacity, then customers -- other customers are actually harmed as a result of that. Because what will happen is, they will buy -- they will buy more expensive capacity, and they'll get assigned a slice of the system.

So, even -- let's say, hypothetically, they need 2 Bcf, 2 million decatherms a year for this. They will go out and buy 2 million decatherms of new capacity at a high cost. Well, that -- iNATGAS isn't going to get charged the cost of that $2 million -- 2 million Dth capacity that they just bought. They're going to get charged a share of the entire capacity being held. So, they will get some of the Tennessee Pipeline, they'll get --

it will all be allocated based on their requirements. So, under that scenario, all the other customers will also get a slice of this higher cost capacity.

So, yes. If there's excess capacity, then this sucks some of that up and it benefits customers. If there's a -- if there's a deficiency shortfall, then they have to go out and buy higher capacity, and that actually harms customers. So, again, it depends on the circumstances at the time.

And, in 2014, NED was on the board, there were any number of projects that were on the board. There was more capacity, that the shortfall wasn't as severe as it is now. It may have been beneficial. At this point in time, I don't know that the capacity requirements that iNATGAS is putting on the system and that the capacity revenues that will be derived from that are a perfect match and actually benefits ratepayers.

Q And any of those capacity releases that result in benefits or negative benefits, all of that will flow through to EnergyNorth customers

through the cost of gas, is that correct?
A Right. The capacity charges are flowed to firm sales customers through the cost of gas.
Q Thank you. So, now then, I'd like to move to the topic of the proposed Keene consolidation. And, in particular, if you have some comments you'd like to make on the points that were made in Mr. Clark and Mr. Hall in their January 2018 rebuttal, I'd ask you to make those comments now.
A Okay. In the Clark/Hall rebuttal testimony, on Bates Page 047, they state that NHGC -- I'm sorry, New Hampshire Gas Corporation was unprofitable for years. And I don't dispute that. But it does beg the question, why Liberty would acquire the system and pay a premium to do so? And when they did come in and petition the Company to -- for the acquisition of New Hampshire Gas, their president at the time stressed that there was great growth and profit potential based on their -- on conversion plans.
And that's -- to date, this filing doesn't really provide a credible business plan. And

there's been some discussion as to why the Company didn't do that. But that's an observation I'm making now, is that it has hasn't been profitable, but I expected, when they sought rate consolidation, we would see something that would support what was presented or suggested at the time of the acquisition.

I would also like to point out that the revenue deficiency that is in the Company's testimony for Keene is -- includes costs that are outside the test year, and it also includes costs that may not be reasonable and prudent.

There are costs related with the 2015 incident. And there's costs related to manning the plant around-the-clock during the winter season. And there was a very high cost to that, to address what the Company itself described is a "minimal risk".

And, so that, if the Company was -- there's a revenue deficiency here that I don't think is justified by what's in the filing. And maybe, if there was more -- they had filed more, that that would have been different. But I would have like to have heard from -- I would like to have heard more regarding why those costs were prudent that were incurred.

But, anyway, that's my response to that suggestion or that observation that NHGC was not profitable for years.

On Page 49 of the Clark/Hall rebuttal, and Mr. Hall spoke of it on the stand, that there's no financial harm to EnergyNorth's customers. And in his -- in the rebuttal testimony, he suggests that a $900,000 deficiency that is, if recovered from EnergyNorth customers, would only cost an average residential ratepayer $4.40.

And I -- that I accept that that's a small number for a residential ratepayer, but I have a problem with the rationale. Basically, if you're going to take that approach, any expense under a million dollars is *de minimus*. When you take a large expense and divide it by 90,000 customers, it becomes a pretty -- it has a pretty small impact.

So, to quote Ben Franklin, "Watch the pennies and the dollars will take care of themselves." I don't think -- I think it behooves the Commission and Staff to look at this and consider it, not that it's a minimal impact on ratepayers, but it is a negative impact on ratepayers.

Q Mr. Frink, do you -- I'm sorry.

A No. Go ahead.

Q Mr. Frink, do you recall on the rebuttal testimony where the Company drew parallels to Connecticut Valley Electric Company consolidations and some water company consolidations?

A Yes. The Company, it starts on Page 50 of the rebuttal testimony, cites several water dockets and one electric docket in which the Commission approved rate consolidation that shifted costs. And I would argue that that -- this is not comparable.

The water -- and there are probably more dockets in which that would be the case. But the fact is, water, electric, are essential services. There is no substitute for water. There is no substitute for electricity. We know that Claremont Gas, a propane-air system, discontinued service. We know Concord Steam recently discontinued service. There are substitutes that customers could avail themselves of, and oftentimes realize a savings through that.

And, so, you know, yes, the Commission has approved rate consolidations that shifted costs. But I don't recall where that's ever been done for natural gas, and I don't think it's appropriate. And, okay, I guess that's about all I have to say on that piece.

Q There was some reference yesterday to a portion of the EnergyNorth system up in Berlin and a portion of the EnergyNorth system in Amherst. Did you want to comment on that and the similarities or the differences between those situations and the Keene situation, in your view?

A Yes. The Berlin franchise was granted, I forget, I was part of that docket. There was a -- EnergyNorth requested the franchise. PNGTS was being built. The prisons were being -- a federal and state prison was being built up in Berlin, and they entered into a special contract with -- I believe it had take-or-pay requirements for ten years that supported the project. And the Commission approved the project. And it is served by capacity on PNGTS. And the capacity that isn't utilized to serve Berlin, that can be wheeled down to Dracut at a secondary receipt point, that capacity could be sold to an asset manager, a supplier, or anybody who has an interest in it. So, it's not that the PNGTS cost is -- has benefit more than just the Berlin customers.

And there are a number -- there is a small propane system in Amherst serving -- I don't know how many customers. It's a small residential system. And that, as mentioned earlier, when Mr. Hall and Clark were on the stand, that it was a program back in the '60s, where you have a utility -- a gas utility expected they would be providing service out in an area before too long, and there were customers that they would be picking up that they could put on propane, and then they would charge them the gas rates when they got out there, they'd pick those up and serve them with natural gas.

There were quite a few of those both for -- for both of New Hampshire utilities. And, with the exception of Amherst, those systems that were fed by propane have either all been converted to natural gas or service has been discontinued to them.

I know, for Northern, I was involved in two line extensions to pick up propane service customers. I was involved in a -- when they terminated service to the Pelham strip mall that was being served by propane. I was here for -- when EnergyNorth extended their line out to Milford and picked up a propane system in Milford, serving 166 homes, and was converted to natural gas.

I was here in 2006, when EnergyNorth discontinued service to a 12-home division in Manchester that was taking propane, and they couldn't economically extend natural gas to them. When they did that development -- when they originally did that development, it's my understanding that there was another large development proposed for across the street that never got built. So, they did extend natural gas to those 12 people. And the tank farm that was serving those people was on one of the customer's property. And when the lease expired, that owner basically was holding up EnergyNorth for a very large payout to continue operating from that land, and the Company terminated service.

Basically, they gave the customers propane tanks and energy efficiency measures, and there may have been a payment involved. But they got them off the propane -- they got them off their natural gas rates and system and no longer had to provide propane service.

So, Amherst is the last that -- the last one of those. And hopefully, at some point, natural gas will reach those customers.

Q Now, do you bring up these historical examples by way of contrasting them to Keene or to show similarities to Keene? What's the point you want to make to the Commission concerning these historical references?

A The point I'm making, and I -- and the Company actually raised this as well when they were on the stand, is that the Keene proposal is closer to what they are proposing in Lebanon and Hanover. So, in Lebanon and Hanover, they have proposed providing CNG and LNG service off, basically, it's a virtual pipeline. And there was a settlement agreement. There's a cost sharing, but there's a separate cost of gas. And it may be natural gas, but it's not pipeline gas. It has different costs. You need to build facilities to provide that.

And, so, this, having Keene, the difference between Keene and Liberty is that -- between Keene and Lebanon/Hanover is that, in Keene, there's an existing propane-air system. It is not profitable. And it hasn't been profitable for a while. And what the -- when Liberty acquired this company, what they were suggesting is that the system could be profitable, basically, by retiring the propane-air system and going to a CNG/LNG system. And, so -- but the difference in Keene is that they have the franchise, and they don't need Commission approval. So, they have started this process, and that's -- but I look at it more as it should be treated similar to Lebanon/Hanover, as something separate and different than the rest of EnergyNorth's customers. And that the Amherst situation is a unique situation that may eventually be rectified, but is not a fair example of what the Keene situation is.

Q And essentially, if I understand, the historical examples you've given were situations where there was an expectation that a gas main be extended to --

A That's correct.

Q -- to fill -- to serve these customers with underground natural gas fed in the traditional local gas distribution company sense, as opposed to Keene, where we're dealing with a CNG/LNG situation. Is that essentially what you're saying?

A That is correct. The propane systems were getting natural gas rates, being provided propane, but the expectation was that they would be provided the same gas as everybody else and at the same rates eventually. So, --

Q Now, does your concerns with the Keene situation involving CNG/LNG involve -- revolve around costs?

A The concerns absolutely revolve around cost. One of the concerns is cost.

Q And how, under the Company's proposal in this case, and then we'll talk about the Settlement in a minute, but, under their original proposal to consolidate rates, how would costs be handled? How would costs of the LNG and the CNG installations and conversions be handled?

A In the original filing, regarding rate consolidation, it's the -- there was an adjustment to a tariff page to allow for a Keene cost of gas. And they said -- and in that tariff change, it said that Keene cost of gas would include production costs. There were no details as to what exactly that entailed. The original filing and in the rebuttal testimony really doesn't say anything really about exactly what is going to be in this, in this Keene cost of gas. So, that's a concern.

To the extent, and we heard some testimony from Mr. Clark and Mr. Hall, as to, okay, the cost of the facilities, the CNG facilities and

LNG facilities will be part of the cost of gas. So, that's a step in the right direction. In the sense that that will ensure that those costs are recovered from the Keene customers that are the reason those costs are being incurred.

Q So, if the CNG or LNG costs ended up being significant or significantly higher than what's expected right now, under the Company's proposal back in -- when their case was filed and in the rebuttal, was that those production costs, CNG/LNG costs, would stay in the Keene Division. Is that your understanding?

A That is my understanding, yes.

Q Okay. Now, there was some discussion yesterday about the expansion into Keene involving the discounted cash flow analysis that the Company had done with respect to new customers that they were hoping to hook up. Do you recall the testimony indicating that those analyses were exclusive of the CNG/LNG costs?

A Yes. That's correct.

Q So, those analyses included only the costs of distributing the main, correct?

A That is correct.
Q Is that one of the concerns you have with the business plan that's been presented before the Commission?
A Yes, it certainly is. And again, I would liken this to the Hanover/Lebanon proposal. In the Lebanon/Hanover proposal, there are rate base items that are recovered through the Lebanon/Hanover cost of gas. And there are rate base items that will be recovered through distribution rates. And the risk-sharing plan actually protects both distribution customers, meaning all of EnergyNorth's customers, and it protects Hanover/Lebanon customers, to the extent the discounted cash flow analysis for Lebanon/Hanover actually includes the rate base that's going to be recovered through the Lebanon/Hanover cost of gas.
In Keene, the rate base to be recovered through the Keene cost of gas is not part of the costs that would be included in the risk-sharing DCF analysis.
Q Now, Mr. Hall and Mr. Clark did talk about a 200 -- and I'm moving to the Settlement now,

but did talk about a $200,000 allowance. Does that cover the concern that you just expressed?

A Well, again, that only relates to the delivery rates. So, it protects EnergyNorth's customers, but it provides a very limited protection for Keene's customers, if this project proves to be unprofitable.

Q So, you would say, I think, if I understand your testimony, that the Keene customers under this arrangement receive less protection than the Hanover/Lebanon customers. Is that a fair assessment of your testimony?

A Yes, it is.

Q Okay. So, you were in the room yesterday when the Company witnesses described the aspect of the OCA/Liberty Settlement concerning Keene consolidation, I believe, correct?

A That's correct.

Q And do you have any comments you'd like to make specifically about that, about the provisions in that Settlement, in addition to what we've just been talking about?

A Right. As I suggested -- as I have stated, moving Keene costs -- Keene rate base items for supply into the cost of gas is a step in the right direction, in that it does reduce cost shifting. And the sharing mechanism, to a very limited degree, is another step in the right direction. Again, that will reduce cost shifting and provide protections to Liberty's customers, and Liberty's customers both on the EnergyNorth system and in the Keene Division.

I am somewhat concerned with the fact that the Company's position was that, for rate consolidation, when they made their initial filing, was that, basically, Keene customers can't absorb a rate impact of 900,000, a revenue deficiency of 900,000. If you're shifting the majority of the costs from -- back onto the -- into the cost of gas to recover it only from Keene, I don't know how that rate impact can be absorbed.

But, again, I have questions as to whether that revenue deficiency is the appropriate deficiency. Because, as I already stated, there are costs in there that are out of -- not in the -- beyond, outside of the test year, and

there are costs that may not be prudent.
Q And on that subject in particular, I think you're referring to the December 2015 incident costs. There's a specific provision in the Settlement that covers that, is that correct, the Settlement, again, between the OCA and the Company?
A Right.
Q Do you have that Settlement in front of you?
A I do.
Q I believe we want to look at Bates Page 007 in the Settlement, Paragraph 6.
A That is correct.
Q So, if you could comment on that paragraph please, and the impacts as you see them.
A Okay. On Bates Page 007, Item 6, "Keene Production Costs and Emergency Response Costs": "The Settling Parties agree that the emergency response costs related to the December 2015 incident and the Keene production costs should be recovered through the Keene specific COG rates over five years during the winter COG period, and beginning November 1, 2018."
That would seem to preclude the Staff

seeking a disallowance in the Keene cost of gas. In essence, this is saying, if the Commission approves this Settlement, the Commission is saying those costs should be recovered through the Keene COG. And even though the Company witnesses said "well, those costs could be disputed as part of the Keene cost of gas filing", I don't see how. Staff could try. But I don't think even Don Quixote would take this one on.

Q So, if I understand your concern, is that the way you read this Settlement, it would preclude a prudence review in the cost of gas?

A That's how I read it.

Q Now, we heard testimony from the Company yesterday that said that, in their view, that's when the prudence review would take place.

A That's what we heard.

Q So, if the Commission were to approve this Settlement as written, would it be your recommendation that they clear up this gray area that you believe exists?

A If they were to approve this, yes.

Q And do you believe that there is adequate time and resources in a cost of gas proceeding to conduct a prudency review of this incident?

A If we started that proceeding now. I mean, we've had issues that have arisen in cost of gas that we knew were going to arise, and you could make a cost of gas filing well in advance, open a docket well in advance of the actual cost of gas filing.

But, in the normal course of a cost of gas filing, where you have, basically, particularly in the Keene filing, four weeks to process the thing, that it would be hard to do this justice and develop the record to make a decision, an informed decision.

Q So, in your view, there would have to be some accommodation made in the procedural schedule of a typical cost of gas in order to handle this issue?

A Yes.

Q Okay. Well, Mr. Frink, that's all I have on the Keene consolidation.

I'd like to move to a third topic, third and final topic, I believe, which is Staff's position overall on the Settlement that's been entered into between the Company and the Consumer Advocate's Office.

CHAIRMAN HONIGBERG: Let's go off the record for a minute.

[Brief off-the-record discussion ensued.]

CHAIRMAN HONIGBERG: All right. So, let's take ten.

(Recess taken at 11:30 a.m. and hearing resumed at 11:48 a.m.)

CHAIRMAN HONIGBERG: Mr. Dexter.

MR. DEXTER: Thank you, Mr. Chairman.

BY MR. DEXTER:

Q Mr. Frink, I'd like to move into the final topic of your direct testimony today, which has to do with Staff's position on whether or not the Commission should adopt the Settlement that's been entered into between the Office of the Consumer Advocate and Liberty Utilities.

I guess I'd ask you to state Staff's position. Do you think the Commission should approve it?

A The Commission should not approve the

Settlement Agreement that Liberty and the OCA have entered into.

Q And I imagine we'll get into some of the -- we will get into some of the details in a minute, but let's just focus, if we would, on the overall revenue requirement, which is the numbers that the witnesses have been talking about over the course of the week.

As you understand it, what was the revenue deficiency that was filed by the Company in their rebuttal testimony, which was the last calculation that the Company provided before the Settlement?

A It was approximately $14.5 million.

Q A requested revenue deficiency?

A That was the deficiency.

Q And what's the revenue deficiency that's built into the Settlement?

A The Settlement has a revenue deficiency -- a stated revenue deficiency of $10.3 million, approximately. Well, actually, that's exact. But --

Q And are those two numbers comparable? Are there some adjustments that you'd like to point out that would put those on an apples-to-apples basis?

A Yes. The 10.3 million revenue requirement increase called for in the Settlement Agreement does -- part of the Agreement moves the gas inventories from rate base in the rate case to be recovered through the cost of gas. And that's roughly 400,000, or 0.4 -- 440,000. Anyway, so, about 0.4, 400,000 is going to be recovered through the cost of gas. So, as part of the Settlement, the Company will get to recover an additional 10.3 million through delivery rates and an additional 0.4 million through the cost of gas rate.

Q For a total of $10.7 million to be recovered as a result of the Settlement?

A That's correct. So, we're basically comparing the 10.5 to 10.7.

Q You're going to be comparing the 14.5 to the 10.7, correct?

A I'm sorry, right. Right. The 14.5 in the rebuttal testimony compares to 10.7 per the terms of the Settlement Agreement.

Q And what's the difference between those two

numbers?
A $3.8 million.
Q $3.8 million?
A 3.8, yes.
Q Now, were you in the room when Mr. Simek from the Company testified as to the amount of that difference that was related to the Settlement on the return on equity piece of the case?
A Yes, I was.
Q And do you recall what that number was?
A I believe it was $1.7 million, is related to their reduction in the rate of return and capital structure.
Q Okay. So, just to recap then, the difference between the rebuttal testimony, and what's going to be recovered through the Settlement, was 3.8 million. And you're saying that, according to Mr. Simek, 1.7 of that was related to the Settlement on the return on equity. Is that correct?
A That is correct.
Q So, if we were to take that $3.8 million difference that you just talked about, subtract the $1.7 million related to return on equity,

what does that leave -- what does that leave?
A That's $2.1 million.
Q Did you say "$2.1 million"?
A Yes.
Q Okay. So, is it a fair characterization then that the Settlement -- well, let me back up a little bit. Were you in the room when the Company described the Settlement as having "taken into consideration all the issues that were raised by Staff in this case"?
A Yes, I was.
Q And that that's how the Settlement was framed?
A Yes, it is.
Q Okay. And were you in the room when the Company testified that, although specific dollar amounts could not be assigned to all those issues that were raised by the Staff, but that there were allowances made in the Settlement Agreement to account for those adjustments?
A Yes.
Q Okay. So, based on the math that you were doing before, is it correct, in your opinion, that the $2.1 million was meant to account for

all the issues that Staff raised?

A That is my understanding.

Q Okay. Now, there's another provision in the Settlement that relates to the amortization of the depreciation reserve imbalance. Is that correct?

A That is correct.

Q And could you point in the Settlement to that provision?

CHAIRMAN HONIGBERG: Off the record.

[Brief off-the-record discussion ensued.]

BY THE WITNESS:

A On Bates Page 006, that's Exhibit 29, the Settlement Agreement, it says "Depreciation" -- there's a section on "Depreciation and Amortization". And under Item 4, Line (e), it states that "The depreciation reserve variance is an under-recovery of 8.9 million, and will be amortized over a five-year period, resulting in annual amortization of 1.8 million" -- well, "$1,780,000".

Q And did you compare that provision in the Settlement to the Company's original

presentation on this issue of amortizing the depreciation reserve imbalance?
A Yes.
Q And what did that comparison show?
A The comparison shows that the rate impact, the impact on the revenue requirement, from what was in their rebuttal testimony, results in a 1.3 million reduction in the revenue requirement. So, when they were depreciating at three years in the rebuttal, by depreciating it over five years, that reduces the revenue requirement by $1.3 million.
Q And so, if we were to take that 1.3 million that's now been identified as related to the depreciation reserve issue, and subtract that from the $2.1 million that you had previously said was going to be allocated to cover all the other adjustments that Staff had made, what does that leave you as the difference?
A That leaves $800,000 for all other adjustments.
Q Now, without restating the entire case, what are some of the other major adjustments that that $800,000 would have to cover?
A Well, first, I would like to say the

1.3 million adjustment for the amortization of the depreciation reserve, theoretical reserve deficiency, is -- should be a $2.5 million adjustment as recommended by Staff.

In the prior -- the last depreciation study that was submitted and was included in a rate case had essentially the same difference, only it went the other way, so it actually reduced the revenue requirement. Mr. Normand, who did that depreciation study, as well as this one, recommended that it be depreciated over two cycles, so 12 years.

Q Let me stop you there, because this is an issue that we haven't gotten into yet, and Mr. Iqbal will be addressing that very issue tomorrow. So, we'll just stick to the numbers now, --

A Okay.

Q -- because that hasn't been brought into the record yet. But I just want to finish this analysis.

A I will. But the point is that the 1.3 --

Q Compares to a Staff adjustment --

A -- compares to 2.5. So, there's another 2.5

that the 0.8 maybe addresses. There's also a -- almost a million dollars that Staff has recommended as an adjustment to account -- to annualize the customer revenues based on the year-end customer count. And that basically ties to the Company is using a year-end rate base, and so the customers should be also reflected is at year-end.

And that issue was also -- I reviewed the Northern rate case, made an adjustment there. I know, in Maine, they also -- the OPA up in Maine made that adjustment in Northern's filing up in Maine. Maine added -- addressed the issue by denying the OPA's request to use year-end customer growth. But, to be fair, it denied the Company year-end rate base, and instead use the 13-month average. So, that's the way Maine approached it.

But our approach is, we should adjust the revenues to reflect what the customer counts are at year-end.

Another major adjustment in Staff's -- as Staff has proposed is half a million dollars related to the Training Center. Another major adjustment is $400,000 related to the iNATGAS overspending.

And we also have a -- well, I guess those are the major adjustments.

Q Okay. And the reason I bring all these up, is this, in a sense, the reason why Staff opted not to join in the Settlement? That, in a nutshell, you felt that the allowances built into $10.3 million settled revenue requirement were not adequate to address the issues that you raised in your testimony?

A We do not feel that that revenue requirement results in fair and reasonable rates that are just rates. It's not -- it's too big a number.

Q And in the past, have you been associated with cases where a revenue requirement was "liquidated", as Mr. Hall described it, or "black boxed" as Witness Mullinax described it? You don't have necessarily an issue with entering into a settlement like that, as long as it produces a result that you can justify is just and reasonable. Is that a fair assessment of your position?

A Oh, absolutely. That's what we did in the last

EnergyNorth rate case.
Q And I believe it's what we did in the temporary rates in this case, if I'm not mistaken?
A I think you're right.
Q Okay. Well, we'll leave it at that. Now, that covers the revenue deficiency portion of the Settlement. But there are other issues in the Settlement that Staff disagrees with, and therefore led to the recommendation -- leads to your recommendation that the Commission not approve the Settlement. Is that true?
A That is true.
Q And what are some of those other issues?
A Well, one of the things at the top of the list is decoupling. We do not believe -- while we're not opposed to decoupling, we believe it should be adjusted for weather.

Another issue that arose yesterday is that the Settlement Agreement related to the step adjustment includes the full expense related to degradation and legal costs associated with contesting that. And that was never the intent of Staff, and I believe we made that clear yesterday. We realized we had made a mistake when doing the step adjustment revenue requirement. We did it correctly for the base rates. And, clearly, the intent was to flip that into the step adjustment. But, inadvertently, Staff flipped the full expense in and corrected that on the stand yesterday.

Q And when you say "the full expense", you mean the full 2017 portion of that, correct?

A Right. Well, actually, I believe the -- there's a full expense that is being amortized over a number of years. And, so, it was -- maybe it is just the 2017 expense. But the point is that, if they are allowed to recover in that, if the Settlement is approved, then they will be over recovering that. They will get full recovery in year one, and then continue to recover that until a future rate case. And that was clearly not what Staff intended. And that wound up in the Settlement Agreement, in the step adjustment. So, we definitely don't see that as being fair and reasonable or resulting in just rates.

Q Now, in fairness to the Company and the OCA that used that number, that correction that

Staff made wasn't made until yesterday, is that true?

A That's true.

Q But you believe that the underlying concept was clear from the start?

A I do.

Q Okay. Now, just to state the obvious, because we spent most of the morning on it, the Settlement -- you disagree with the way that the Settlement handles the Keene consolidation, correct?

A Oh, I do. The consolidation of the Keene rates, I don't think it provides adequate rate protection or has adequate financial protections for ratepayers against what could be a bad investment.

CHAIRMAN HONIGBERG: Don't rehash the --

WITNESS FRINK: Yes.

CHAIRMAN HONIGBERG: -- the 45 minutes that you spent with Mr. Dexter earlier.

WITNESS FRINK: I will not.

BY MR. DEXTER:

Q And with that, I will just ask if there's anything else you'd like to say in closing with regard to your recommendation that the Commission not adopt the Settlement? And if not, that's fine.

A Well, again, one small issue is that I do believe some of the costs that are -- some of the adjustments may have been imprudently incurred, and approving the Settlement adjustment **[**Agreement**?]** would, in essence, allow recovery of those costs.

And with that, I conclude my testimony.

Q Well, we can't leave that one without clearing it up. I assume you're talking about their Training Center and, to a certain extent, the iNATGAS investments?

A That, as well as the Keene 24-hour manning the plant.

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

CHAIRMAN HONIGBERG: All right. So, we will take our lunch break now. We'll try and come back as close to one o'clock as we can.

When we return, Mr. Sheehan, you'll

have a chance to ask your questions; Mr. Kreis, anything you have; and then the Commission; and then back for redirect, if any as necessary.

So, we'll take our lunch break.

*(Whereupon the lunch recess was taken at 12:06 p.m. and ends the Morning Session of Day 4. The hearing continues under separate cover in the transcript noted as "**DAY 4 Afternoon Session ONLY**".)*