In The Matter Of:

Rhode Island Public Utilities Commission

National Grid Overview of Electric Rates

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

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National Grid :
Overview of Electric:
Rates :

DATE: January 22, 2015
TIME: 1:00 p.m.
PLACE: PUC
Jefferson Blvd.
Warwick, RI

PRESENT:
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MARION GOLD, OFFICE OF ENERGY RESOURCES
DANNY MUSTER, OFFICE OF ENERGY RESOURCES
CHRIS KEARNS, OFFICE OF ENERGY RESOURCES

(HEARING COMMENCED AT 1:10 P.M.)

MR. ROBERTI: Good afternoon, everybody. Thank you for joining us today. This is Docket 4545. We open this docket to review electric rate issues in anticipation of the 2015 rate design review that will take place pursuant to 39-26.6-24.

I think you all know about the renewable energy growth program. I think it's fair to say it represents an ambitious undertaking by the state to develop renewable energy resources, and equally necessary is to ensure that the distribution system remains robust to effectuate the legislative purpose and this program, and that the cost be allocated in an equitable manner across all customers, including program participants.

I want to thank our Commission Council, Ms. Wilson-Frias for advancing the ball on this. We're trying to stay ahead of the curve, because we have much to do in anticipation of the July 1, 2015 case filing by National Grid. We are attempting here to gather as much information so that we can facilitate an understanding of these issues. There are a lot of complicated issues. So I thank you for all coming here today.

It's our intention to be as transparent and open as possible. The parties sitting around the table today have been very involved and have been afforded an opportunity to hear National Grid's presentation and will be afforded an opportunity to ask questions as well after. After we conclude, I do want to open it to public comment.

With that, let me first do some introductions. My name is Paul Roberti. I'm a Commissioner here at the Commission. Chairman Met Corin will not be here today. To my left is Commissioner Herbert DeSimone. I think it would be best to have everybody go around, introduce yourselves. Most of you we know, clearly National Grid and OER. If you're from an NGO, it might be useful to just describe your organization and your membership, so that the Commissioners and staff are aware of who you represent and who your members are.

With that, I'll ask for appearances by Commission staff, and then we'll move around the room.

MS. WILSON-FRIAS: Cynthia Wilson-Frias, Commission's legal counsel.

MR. NAULT: Alan Nault, Commission rate analyst.

MR. BIANCO: Todd Bianco, principal policy associate.

MR. LABEL: Mark Label, staff attorney for the Acadia Center. We are a foundation funded nonprofit dedicated to advancing the clean energy future.

MS. MALONE: Leslie Malone, also with the Acadia Center.

MR. ELMER: Jerry Elmer, Conservation Law Foundation and one of the principal authors of the section that Commissioner Roberti adverted to.

MR. HANDY: Seth Handy from Handy Law. I represent developers and municipalities in this energy space.

MS. BESSER: Janet Besser with the New England Clean Energy Council. We are a clean energy business association. We have 200-plus companies who are in clean energy business expanding clean energy, solar, wind, hydro, all sorts of distributed generations.

MS. PENNOOK: I'm Charity Pennook, also with the New England Clean Energy Council.

MS. LYONS: Karen Lyons, Attorney General's Office for the Division.

MR. RUSHER: Danny Rusher, Office of Energy Resources.

MR. KEARNS: Chris Kearns, Office of

Energy Resources.

MR. ROBERTI: I take it this is National Grid.

MR. NEWBERGER: Jeremy Newberger with National Grid in the energy efficiency area.

MR. ROUGHAN: Tim Roughan, regulatory.

MR. ZSCHOKKE: Peter Zschokke, regulatory.

MR. LAFLAMME: Mike LaFlamme, National Grid regulatory.

MS. LLOYD: Jeanne Lloyd, National Grid regulatory.

MS. O'BRIEN: Celia O'Brien, National Grid's in-house counsel.

MS. BURNS: Terry Burns, National Grid regulatory.

MR. ROBERTI: Welcome, Commissioner Marion Gold. Ms. Wilson-Frias, are there any administrative matters that we need to address before we proceed to National Grid's presentation?

MR. WILSON-FRIAS: I don't think so. What we posted in Docket 4545 is a little memo explaining what this docket is, which you did a nice job of summarizing. National Grid does have a presentation which will also be posted on the website.

There are extras for anybody in the audience to follow along.

MR. ROBERTI: Why don't we proceed with the presentation? Who is going to lead the presentation this afternoon?

MS. O'BRIEN: Hi. Celia O'Brien for National Grid legal. Jeanne Lloyd will start off our presentation, and then turn it over to the other speakers. We are pleased to have the opportunity to provide the overview of Narragansett Electric distribution rates.

MR. ROBERTI: Does everybody have a copy of the presentation?

MS. LLOYD: The first slide just kind of lists sort of the top six we expect to cover today. As Celia indicated, each one of us is going to have a different section to talk about.

First of all, we're going to go over some of the basics, what the rate classes look like and some of the statistics associated with each of the classes, take a look at the overall revenue structure of the company, then some of the typical bill components.

Michael LaFlamme is going to talk about the distribution components specifically and some of the rate mechanisms that we have associated with the distribution system. Terry is going to discuss some of our residential assistance programs. I'm going to talk about some of the renewable energy programs we have. Jeremy will talk about energy efficiency and our system reliability plan. Then Peter will finish up with a discussion of some principles of rate structure and some of the specifics of our residential in general service rates.

Let's start right away with the basics. Flipping to Slide 4, what we're showing on Slide 4 is on the left-hand column is a listing of each of the designations of our rate class. Next to each one is a description of what each class, the customers that are in each of the rate classes.

We have two residential rate classes. A16 is what we call regular residential customers. A60 is for our low-income customers. On our residential rates, primarily we have individual homes, apartments, condos. We also do allow farms and churches to be billed on that rate as well. The low-income rate is available to residential customers who meet the criteria who are receiving certain means tested benefits.

The next series of rates are general service rates, rates available to our commercial and industrial classes. CO6 is our small commercial and industrial class. Types of customers that you might find in these rate classes, convenience stores, gas stations, small sandwich shops, sometimes stores in strip malls, basically smaller-sized customers, smaller retail customers.

GO2 is what we sometimes refer to as our medium general service customer class. It's for any customer who in size is greater than 10 kilowatts. Types of customers you might find here would be larger office buildings, drug stores like CVS, Walgreen's, larger retail establishments, restaurants, that type of establishment.

G32 is for our larger CNI customers. Again, it's size related. Customers who are 200 kilowatts or larger are required to take service on this rate class. These types of customers would be larger grocery stores, WalMarts, Targets, schools, hospitals, manufacturers, office complexes, things of that sort.

Rate G62 is an optional rate. It's for our largest customers. It's for, like I said, it's optional for customers who are over 5 megawatts or 5,000 kilowatts. These would be the largest manufacturers in the state, large universities, Naval facilities, things like that. These are very large customers.

Rates B32 and B62 are the mirror image of G32 and G62. The same type of customers would be in those rate classes. They're larger NCI customers. They are back-up service rates. It's for customers with onsite generation.

The next series of rates, which begin with the letter S, are outdoor lighting rates. S057 is for customer-owned lighting, which is a new rate we just implemented this summer. S06 is company-owned lighting, but it's decorative. S10 is private area lighting, and S14 is company-owned lighting. These would be our municipal customers.

Final two, XO1, single customer for this rate, trains, Amtrak. MO1 is for merchant generator or station power.

The next page, same rate classes that you see. These are just a few of the statistics related to each one, the number of customers that we serve in each class, the total kilowatt or megawatt, our delivery associated with each class. Sort of the average or typical customer that you would see in each of the classes in terms of kilowatt hours and KW, if the customer has a demand component in its rate.

Any questions at this point about any of these classes?

MR. ROBERTI: If there are questions -- do you know what we may want to do? Most of you have placards. Tip it up. That way I will know, and we'll let you cut in with questions. Keep the dialogue moving. Welcome Mr. Steve Scialabba from the Division of Public Utilities and Carriers as well.

MS. BESSER: Quick question. Averages, that's the average use per month?

MS. LLOYD: Yes. It's really derived by taking the ano-usage divided by the number of customers, but it would represent monthly usage.

MS. BESSER: Thank you.

MS. LLOYD: Sorry, number of bills, not number of customers. Slide 2, again, just continuing with some of the basics associated with each of these rate classes, since this docket is really dealing primarily with distribution charges, that's all I included on this page.

It's kind of a look at the structure that we have currently for each of the classes. Our rates are primarily one of three types. It's a customer charge, which would be a fixed monthly charge, demand charge, which would be a per KW, kilowatt charge, and a volumetric charge for kilowatt hour charge.

The customer charge you can see for each of the rate classes is on Line 1. What I did on the line underneath each of the charges is to indicate what percentage of the total revenue requirement associated with each class is collected in that particular component.

For example, rate A16, residential rate, approximately 18 percent of the total cost of serving that class is collected through the customer component. The rest of it is in the kilowatt hour charge. G32, for example, 30 percent is collected in the customer charge, 40 percent in the demand charge, and the remaining 30 percent in the energy charge.

MR. ROBERTI: Can I ask you a question on that? The 18 percent, is that for an average customer, say, using, typically you use 500 kilowatt hours per month, or does that percentage pretty much remain constant across the board?

MS. LLOYD: This is constant. It's really talking about the total dollars, the total revenue requirement applicable to the class. So if this class was 200 million, like I don't know what it is, means 18 percent of the 200 million is collected through the customer charge.

Moving on to the next section, a quick look at the overall cost structure and some of the typical bill components for each class. Slide 8 just gives a quick look at our annual revenue on a total company basis. This format is intended to be similar or identical, actually, to what a customer would see when they look at the bill.

In other words, when they look at their bill they will see each of these categories and charges associated with each of these components. Our bills are divided into two sections, delivery and supplied service section. Under the delivery service charges, I broke it down, again, the way we show it on the bill. So we'll have distribution charges. I won't list them all.

You can see how they show up on the bill. Within each of these components we may have a breakdown of other charges that roll up to these main categories. What I've done is beside each primary component, I indicated what other types of charges may be included.

For example, in the distribution line on the bill, that will include the base distribution charges as well as our infrastructure safety and reliability, our ISR plan charges, as well as our revenue decoupling charge.

In the supply section we have standard offer service charges. We also have a renewable energy standard charge. These are each their own line items. The reason you see the color coding on this chart is because the items that are in color are the ones we're going to dive a little bit deeper into in the rest of the presentation.

The other charges, transmission, transition and standard offer, although important parts of the bill, obviously we're not going to dig into this in this particular presentation. The slide under annual revenue indicates exactly that, the annual revenue that we bill customers through each of those components during the year.

Next we list what the percent that component represents of the total overall bill or overall revenue. The cross-reference slides indicate that later on we're going to deal with each of these components. That tells you where in the presentation you can find the deeper guide for each one.

Next page is the very same thing, only at the rate class level. So all I've really done here is to take those total revenue dollars and show for each rate class how much in total those customers are billed in each category throughout the year.

MR. ROBERTI: Any questions?

MR. LABEL: Slide 8, when it all totals up to $1 billion exactly, is that the actual number?

MS. LLOYD: That is, when you say the actual number, I mean, that is what each of these components during a representative year would, that is what the total would be.

MR. LABEL: Thanks.

MS. BESSER: Is this number from the test year of current rates?

MS. LLOYD: What I've done is I've taken the most recent filing in each of those particular categories. Unfortunately, our filings occur, fortunately or unfortunately, different times throughout the year.

They sometimes represent different periods. The rate period might be April through March. In another category it might be January through December. They do not all line up to the same time frame. I took the most recent 12 months in each of the filings that we submitted.

In Slide 10 --

MR. KEARNS: Just a couple of questions. On Page 8 under energy efficiency, is that strictly the electric, or is that electric and gas?

MS. LLOYD: Everything here is just

electric. The LIHEAP enhancement plan is also a combined electric and gas program. All I've done is I'm showing the electric piece of each of those components.

MR. KEARNS: In terms of the long-term contracting in terms of annual revenues, what this is representing, are these numbers also factoring the remuneration incentive payment?

MS. LLOYD: Anything that is running through the rates, yes.

Slide 10 is the same information really, only at a typical bill level. This is what a customer truly would see if they open the bill from us. These are based on the rates that are currently in effect, based on the type of customer that is shown at the top.

I haven't included all of the rate classes here, just because it tends to make the slides busy. I picked three of our primary classes. I'm just showing for those three classes what the typical bill would look like based on, for example, a residential customer, 500 kilowatt hours per month. Based on our current charges is what each customer would be billed on a monthly basis.

MS. BESSER: Why the renewable energy distribution as a credit?

MS. LLOYD: The renewable energy distribution includes two charges; the net metering and long-term contracting for renewable energy recovery. The way we set that charge, it's a forward-looking charge. We estimate what we think we're going to incur in the upcoming six-month period.

That cost is based on what we expect to pay under the contracts that we've executed less what we expect to, the proceeds we expect to receive from selling the products in the market, the energy to IZONE (sic) energy market and renewable energy credits.

For this particular six-month period, we expect some of those contracts to be below market. It has resulted in a credit for this particular six-month period.

MR. DESIMONE: I thought the LIHEAP enhancement charge was 73 cents per month?

MS. LLOYD: That is a good point. I'm glad you said it. On our bills we show the charges, and then a separate line item will show gross earnings taxes. Just due to space I had on the chart, I put the gross earnings taxes in each of the components. So it's 73, the LIHEAP charge of 73 cents, including the gross earnings tax. Thank you for bringing that up.

Next section is going to look at some of our distribution rate mechanisms, and Mike will take over at this point.

MR. LAFLAMME: Thank you, Jeanne, and thank you for providing us the opportunity to be here and present today, Commissioners Roberti, DeSimone and all of the attendees. When it came to my attention that this was intended to be a tutorial kind of basic presentation of what it is our rates actually are intended to do, how they interact with one another, I've been doing this a long time. I guess I live it every day. I assume everybody has the same kind of focus as we all do here.

I think it's worthwhile just to take a couple of minutes and kind of ground us all into really what does National Grid do. We are a monopoly. We're the last of the natural monopolies in this country. With that comes some obligations and some rights as well.

I have been schooled to adopt a regulatory compact kind of ideology for the ability to be a monopoly, or for the benefit of being a monopoly. We have to provide our services to customers. It's an obligation. It has to be provided in a nondiscriminatory way. Nondiscriminatory in terms of access and also nondiscriminatory in terms of cost.

We have to do that.

Now, with that obligation comes certain rights. With that rights system we have the right to recover our costs. The costs are approved by this Commission who have the sometimes unenviable position of having to make difficult decisions.

I would like to think in Rhode Island we have been blessed with a Commission that has taken on some hard decisions. I think it has always acted in both preserving a stable and strong utility company and also keeping the interest of customers at heart.

Basically we're a cost recovery business. We incur costs on behalf of our customers to provide our service to customers. We present them to the Commission for approval, review and approval.

Then we bill those rates. Bottom line is, we are a cost recovery business. We do our very best in rate design and cost allocation. We have with us today Peter, Jeanne and Terry who know more about cost allocation and rate design than I do.

Certainly our desire here is to provide a set of rates that are equitable and recognize the cost causation principles and attempt to get to a place where customers are paying what they should be paying for the services that they're getting.

I've been asked to present the kind of the distribution charges. The distribution charges really represent our base rates. That is the lion's share of what our distribution business is funded by. That is where we earn a majority of our return for our shareholders. We are a public company.

While I know the folks at this table I've worked with for many, many years, more years than I'd like to admit, but it's been certainly a great ride. There is a return component in that. We need to collect dollars for our shareholders.

While we preserve the interest of our customers, I think very well in terms of what it is we present to the Commission, we also have a fiduciary responsibility to insure that our shareholders, the investors in our business, are also afforded the opportunity to earn a fair rate of return, which is also part of that regulatory compact. That we are afforded the ability to recover our costs, including a return on those investments.

With that as a foundation, I guess we could turn to Slide 12. Again, following Jeanne's lead here and the color coordination, Jeanne, I must admit, did the bull work on putting this presentation together. I hope it flows. I think it does.

The distribution, I'm not sure what color that is, but that ties to the number that you saw on the previous page. As you can see, our total distribution charges for an annual period as in effect today recovers a little over $261 million. The lion's share of that, obviously, is our base rates. Those are the rates that Jeanne talked about in terms of biometric charges for kilowatt hours, demand charges for peak demands, and then customer charges, which are the fixed monthly charges that we bill our customers.

So each of these individual charges and, actually, a couple of other concepts I'll be discussing in turn on the following pages. If we turn to Page 13, this kind of template of distribution rates, you'll see is one that is held throughout this presentation.

For each of the individual rate categories, you're going to see a page that looks like this. It describes the purpose of the rate, the peak season of rate changes, effective dates, the amount that we're recovering currently over an annual period, and then other pertinent information.

So basically our base rates are established via a base rate case that the company either on its own accord files with the Commission generally as a result of earning a return for its shareholders at a rate less than is reasonable. It provides cost recovery, as I mentioned earlier, of our entire cost of service.

When I say our entire cost of service, it recovers all of our operating expenses, you know, things like wages and operations and maintenance expenses, property taxes, income taxes, also includes a return of and on our investment.

I'm sure it comes as no surprise that an electric utility is a very capital intensive business. We spend a lot of money maintaining and shoring up our system. That investment comes at a cost.

When you hear a return of and on, it really represents two things. Return of is simply depreciation expense. If you assume an asset is going to last 50 years, a Polaris piece of wire is going to last 50 years and it cost $50, we need to recover $1 a year for 50 years to cover that investment. That's the return of.

The return on that asset is simply the interest or carrying charge that the company needs to recover to actually fund the cost of the capital. In that same $50 scenario, we, National Grid, have to raise $50. We do that in generally one or two ways. We go out and borrow money from the bank. That is very easy to understand what that cost, to go out and borrow $25 at 5 percent. I know it's going to cost me 5 percent of $25, or a dollar and a quarter. However, we also raise capital from shareholders or equity. That is the return on equity.

You will see we talk about return of equity in several places here. That actually represents the profit that we attempt to earn for the benefit of our shareholders. We have to, we have to compete with other companies to raise that capital. You, as an investor, can take your dollar and invest it in National Grid, buy a dollar share of National Grid, or you can buy a dollar share in Coca-Cola and/or Pepsi.

MR. ROBERTI: With the exception of Commissioners.

MR. LAFLAMME: With the exception of Commissioners. Good point.

We actually do compete. What we need to provide, we need to provide a level of earning that is attractive enough for investors to actually want to invest in National Grid. That is probably the biggest contended issue in a rate case is what that return on equity is.

It's established through the rate case process. It's discovered. It's reviewed, and ultimately that provides our profit on our base rates.

So these rates, once they're set, are in place until we file or are asked to file. Because the Commission on its own accord could file to have us come in and file for a base rate investigation. The rates are in effect and do not change until another base rate case is adjudicated and another order from the Commission comes out.

As was shown earlier, we are currently billing rates that are designed to recover $251 million. So that is our total cost of service today for Narragansett Electric. We'll talk about revenue decoupling and how that plays into the equation here.

Ultimately that is what it is we're attempting to recover on an annual basis. The weighted average cost of capital, very last item on this page, is 7.17 percent. That is what we, that is the return of our investment. So that $50 number that we talked about before, we also, besides recovering that $1 of depreciation expense, we would recover 7.17 percent of that, which is $3.58, something like that, on that investment. We've recovered that return.

That is intended to pay the cost of capital, interest expense, and return on shareholder investment.

MS. BESSER: This is helpful. Somewhere in the presentation are you going to talk about how, what element of the bill -- I'm missing the word -- but is the customer charge, demand charge, kilowatt hour charge that these costs are recovered in?

MR. LAFLAMME: All three.

MS. BESSER: These costs are recovered in all three components you see on the bill?

MR. LAFLAMME: Ultimately rate design is that. We have a $251 million pie. Our rate allocation folks determine what components of the base charges are going to recover that $251 million. I think that was the subject of a previous slide that actually broke out the percentages of those.

MS. BESSER: That's right. I'm setting this up for a later question.

MR. LAFLAMME: You're quizzing me. Thank you.

If we move on to Page 14, I'll try and tie these in, because they're all interwoven in one way or the other. As I mentioned, base rates are established and then they are fixed. They do not change year on year.

I can tell you for sure what does change year on year is our costs. Sometimes they go up to the extent that we can detect deficiencies in the work we do to provide our distribution service. Sometimes they go up because Jeanne, Celia and Terry need big raises every year. Our costs go up.

Bottom line is we know that static level of cost of service is not static, right, the recovery of that cost of service. I'll speak a little later about revenue decoupling, which actually results in us recovering that cost of service, no more/no less through a reconciliation mechanism.

I think more likely than not over time our cost of service increases, if for no other reason that we are a capital intensive business and we invest a lot of money in the State of Rhode Island. I think upwards of $70 to $80 million a year just for our electric business.

So the ISR plan, which was legislated, actually provides funding to the company to support those $70 to $80 million of capital investment that we added since the last time that we, that our case rates were set.

We file annually with the Commission. We negotiate with the Division on a plan that hopefully is agreed upon in all respects, and ultimately submit that plan with the Commission for approval. So every year there is an incremental charge related to this

ISR plan. It is intended to provide the ability for the company to make sure that it absolutely does whatever it needs to do to maintain the system.

That is an obligation for us in any event. We would do that in any event. But with decoupling, because our revenues are in effect fixed, because we reconcile to this $251 million number that we spoke about before, absent the ISR-type program, we would always be coming back in here for a rate base. That generally is not the most economical way to do things.

This was legislated. It provides the ability, again, to provide the funding, to keep the cash flow that we need to actually invest in our business. The reconciliation period, as you can see here, the rate itself goes into effect every April 1. In August we do file a reconciliation for the prior April to March period.

That reconciliation amount, plus or minus, based on what our ultimate actual cost to service was for the investment, goes into effect in October. It just reconciles what our actual costs of those capital additions were versus what it was that we collected in the rate in the first place.

Currently we're recovering around $12.3 million. The ISR plan does include some O&M dollars. The biggest piece of the ISR program is vegetation management. Tree contacts and tree problems is the number one cause of electrical outages for Narragansett Electric. Of that $12.3 million, roughly $8.5 million of that is vegetation management. So 80 percent of our request is for vegetation management.

We reconcile to the dollar. If we spend $8.5 million, which is what our estimate is, we're even. If we spend $8 million, we credit customers half a million. If we spend a little more than that, we come in and request to recover that as well.

MR. NAULT: That 12.3 that is showing up as the current recovery, if I compare that to Slide 12 where annual revenue is 10.5, looking at that 10.5, does that mean for the current year, which I guess is Fiscal 15, you're collecting the 12.3, but that is being offset from the recovery of the prior years?

MS. LLOYD: That's right.

MR. LAFLAMME: Net of the two numbers. Maybe a little rounding, yes.

MR. MUSTER: My understanding is the annual ISR plan is somewhere in the $70 million range. What does the $70 million represents versus the $12 million here?

MR. LAFLAMME: That is the capital investment. Again, if I go back to my $50 example, if I spend $80 million, the return of and the return on that is this 12.3. I don't have to recover $80 million in one year. I need to recover 7.71 percent of that, plus the depreciation of that.

The capital amount is recovered over a long period of time. The return on the outstanding amount is recovered as well.

MR. ROBERTI: Not unlike a mortgage?

MR. LAFLAMME: Not unlike a mortgage.

MR. ROBERTI: What is the typical time frame, just for educational purposes, for some of these assets?

MR. LAFLAMME: Our effective depreciation rate is 3.25 percent, so it's like 33 years.

MR. ROBERTI: Good.

MS. BESSER: Again, these costs are recovered in a kilowatt hour charge, customer charge, all of the above?

MR. LAFLAMME: Kilowatt and demand charge. It is rate designed. If there are no other questions, we can move on.

Page 15, distribution CIACs, which is Contribution in Aid of Construction, this is not a rate, per se. I kind of led off my discussion here with cost causation and kind of who pays for the benefits that are being received.

CIAC is actually contributions that we collect from an individual customer to the extent that they're asking for service upgrades or a new-up customer investment by the company. For our residential class, small classes, we actually calculate a center line cost per foot, or cost per foot.

So that if a new customer is a quarter mile off the road, there is an allowance of a certain number of feet that all customers are entitled to. To the extent that we have to extend a line further than that, there is a charge based on a cost per foot.

That cost is generated by taking a sample of what the company incurs to do these jobs over a period of time. It takes an average, and that's what that cost per foot is and that's how it's calculated.

For bigger customers, we actually have a contribution factor that is calculated. It's calculated by determining what the incremental revenue is expected to be from either a service upgrade, or in the case of a new customer, what their expected costs -- what their expected revenues are going to be. We provide an allowance against the cost of the job for what we believe that revenue would support.

Again, if I go back to my very simple cost of service, $50 allowance, if our total cost for service is 20 percent, so for every dollar we need 20 cents to support that for operation expenses, the total cost of service. What we do is we take a dollar of revenue and divide it by our carrying charge or carrying rate, which is 20 percent. We would assume that $1 of revenue would support $5 of investment.

To the extent that somebody is coming in and is expecting to provide a dollar of revenue to us and the job costs $5, their contribution would be zero, because we would say that their incremental revenue is supporting that investment.

Again, back to cost causation principles, that would suggest that there are no costs to be shared by everybody else. Ultimately that $5 investment is going to go into our rate base. When we file rates the next time around, there is a dollar of incremental revenue from the customer who received that benefit. There is no subsidization of cost to all other customers.

The tariffs that govern these, are these Policy One, Two, Three line extension policies. Again, there is no rate. It's an instance-by-instance calculation.

MR. SCIALABBA: Do you look at this revenue contribution over a period of time? Is it five years, the customer contribution?

MR. LAFLAMME: It's an annual number.

MR. ZSCHOKKE: We look at it over the life of the unit to the average depreciation.

MR. ROBERTI: Does that mean it's 33 years?

MR. ZSCHOKKE: Yes.

MR. ROBERTI: Any other questions?

MR. LAFLAMME: The next slide, Slide 16, pension and post-employment benefits, other than pension. This is a reconciliation mechanism that ensures that the company recovers no more or no less than what it actually incurs for pension and post-employment benefit costs.

Typically those costs are very volatile. They're volatile for reasons that are out of control of the company. I could bore you for hours with pension and PBOP actuarial stuff, but I will not do that. Bottom line is, the way the costs are derived include actuarial assumptions, mortality rates, discount rates, rates of asset gains, and the rate of interest has a huge impact on what that present value liability is for pension and PBOP, as you might imagine.

So as interest rates go up and down, our present value liability for these future obligations go up and down. That is the primary factor of how we determine how much expense we need to recognize in a given year. So the Commission has recognized that these costs are volatile. They do change annually, for no reason of the company.

I can tell you that the company has over the years taken some pretty aggressive measures to reduce costs. I'm 172 years old, so I enjoy a defined benefit plan. Employees, I think, since 2000, maybe even earlier, no longer participate in the defined benefit plan for National Grid.

They participate in a 401(k) plan, but the day of the defined benefit plans for National Grid is gone. Knock on wood, I got in there under the wire. This mechanism, again, it's an annual mechanism. We charge, the rate begins on April 1, goes to March 31. It's intended to recover the amount that, the amount above or below. So this can be a credit, and it has been above or below our base rate allowance.

As it indicates down here, in that $251 million number that you saw earlier, $13.7 million of that is for pension and post-retirement benefits. To the extent that we have $12.7 million of cost in a year, we will credit customers $1 million. If it's 14.7, we would seek recovery of that increment. Right now the factor is zero. We actually are recovering in base rates right around our actual costs.

No questions? I'll move on to revenue decoupling. Revenue decoupling was established four years ago, 2010. It was legislated. It's a mechanism that provides the company assurance that it will recover its cost of service, that static cost of service, so the $251 million number.

There was a natural disincentive for a utility company or any company that derives its revenues based on unit, unit prices to actually encourage customers to use less of those units. So Coca-Cola is not telling people, Don't drink Coca-Cola. National Grid was very aggressively and wanted to encourage their customers to use less kilowatt hours. That's the major way we recover our revenue.

So what decoupling did, it really just broke the link between the amount of revenue that the company is allowed to retain from the number of units that it sells to its ultimate customers. To the extent that our energy efficiency measures reduce the usage of electricity over time, absent decoupling, our revenues would go down. Not a situation that is sustainable, clearly.

I think it was recognized by the legislature; hence, we wound up with a revenue decoupling. The period for decoupling is an April to March 31 period as it indicates here. The mechanism simply takes a look at what we actually bill customers based on those unit prices and compares it to the $251 million kind of target revenue, annual target revenue that we're hoping to recover, and just reconciles plus or minus. Either we credit customers, we actually bill more and we surcharge customers, or we bill less.

Currently we are, yes, the target -- I'm looking for the reconciliation. Our current reconciliation billing is only $100,000. It has been more than that. Things like -- not as much as it impacts gas, our gas system, but weather has an impact. Weather has an impact. If we have a very, very hot summer, we're a summer peaking utility; we sell more units. We consequently receive more revenue in the door. We would have to give that back, if it's more than $251 million.

Next page, if there are no questions, the service quality plan. This also is not a rate, but I think it's important that we talk about it. The company is required to maintain service standards, primarily around reliability and customer satisfaction.

So there are metrics that have been established by the Commission that we need to maintain. In reliability, we have to measure our outage frequency and our outage duration. To the extent that our outages, in terms of numbers and in terms of duration, are greater than the established baseline, we pay a penalty.

This is a penalty-only plan. There is no ability for the company to actually earn incentives, though the plan does provide for penalty offsets. In one category of service quality, the company outperforms the baseline, it can accrue some offsets to the extent that there is a penalty in another.

Right now it looks like we're funding about $16,000 of service quality penalties. I honestly don't know what these penalties are for. If anyone is going to ask, I'll save you the time. I don't know if anybody here knows.

MS. LLOYD: From the 2012 plan.

MR. LAFLAMME: Okay. I think it's something certainly that the company strives to do. I would like to think we don't need this stick to do our, to perform to the best of our ability. Certainly it provides the proper incentive for us to do so.

I think to a person here and also our operations folks, every day the intent is to make sure the lights stay on for all of our customers. Any other questions?

The last thing, I think, this is the last thing to talk about, an excess earning sharing mechanism. This really is the final kind of, I guess, umbrella for customer benefit here. Actually, it provides the company with an incentive to perform well.

As we talked about earlier, base rates, decoupling, the company will bill and ultimately retain $251 million of distribution revenue. That is, that represents the total cost of service which includes the profit margin for the utility.

To the extent that in a given year we can operate our business at something less than $251 million, there is some premium return there. Our return on equity, as approved by the Commission, is 9.5 percent. To the extent that the company earns more than that, we have to share that earning, that over-earnings with customers.

So it provides the right balance of incentive for the company to continue to seek out efficiencies on behalf of its customers, certainly. To the extent that we earn more than 9 and-a-half, we share. The kind of sharing metric is we share 50 percent of the first 12 percent above 9.5 percent. Then we share 75 percent of everything beyond that.

So if the company, and I say if, I could only wish it was earning 11 percent, is 11 and-a-half percent, or 2 percent more than our 9 and-a-half percent allowance, we would give back 1.25 percent of that. Half a percent for the first 1 percent and three-quarters of a percent for the second percent. That's how it is.

We have, since our last case, we have not been in an excess earnings position. We would love to do so. We strive to do so, certainly. I can tell you that my bosses would like it even more than I.

Ultimately this is a very, very valuable mechanism for both the customers and for the company as well. It absolutely provides the right incentive for us to do the best we can to mitigate our costs and operate as efficiently as possible.

MR. ROBERTI: Thank you, Mr. LaFlamme. Any questions? All right. Mr. Zschokke, are you up next? Terry Burns is.

MS. BURNS: One thing we do want to talk about very quickly, because we thought it was important, is the assistance that we provide to some of our neediest customers. There are two plans, one of which is highlighted as one we wanted to talk about today, the LIHEAP enhancement program. We would be remiss if we did not also mention the benefit that we give these customers through base rates.

If you turn to Slide 21, please, I just want to quickly go over these two mechanisms that provide a level of benefit to customers on rate Class A60, which Jeanne mentioned at the beginning of the presentation. We do have discounted base rates for these customers to provide a certain level of assistance to help them pay their bills.

They are charged no customer charge, and their base energy charge is discounted 50 percent from the full residential kilowatt hour charge. It's not subject to reconciliation, but for the fact that we have RDM and our total revenue is reconciled, as Mike explained. The amount of the benefit on a total company basis is determined as part of a rate case.

The amount that is currently reflected in base rates is $6.4 million annually. The LIHEAP enhancement program, again, is statutory. It covers both gas and electric, but we're here to talk about electric today. It's a statutory program that provides additional assistance for customers who receive the federal LIHEAP grant.

It's funded, again, by electric and gas customers up to $10 million a year. Annually the OER and DHS set the grant level, make a filing with the Commission to determine both how much the surcharge should be, which is the 73 cent per bill for both electric and gas, and how much of an additional grant would be provided through this program when the customer has received a federal LIHEAP grant.

We also reconcile the amount of funding that is received through the surcharge as compared to the level of grants credited to eligible customer accounts. The reconciliation period, as shown here, is October through September. We do file reports twice a year to show the status of the funds available for grants during the upcoming months.

The surcharge itself changes every January 1. The electric only recovery, so what is generated by the 75 cents per customer per month is $4.5 million annually. At September 30 in a report that we filed on the reconciliation of the LIHEAP enhancement fund, it was $5.1 million overfunded, which means there's $5.1 million of funds available to be given as grants to customers eligible in the State of Rhode Island.

MR. ROBERTI: That would be drawn down at

this point?
MS. BURNS: There are monies still going into the fund through the 73 cent surcharge. As the LIHEAP grant gets processed, that balance will draw down.
MR. ROBERTI: Any idea what the current balance is right now?
MS. BURNS: I don't know off the top of my head.
MS. LLOYD: I think we just provided it to someone. I can't recall off the top of my head either.
MS. BURNS: On Slide 22 we just wanted to show you some of the numbers around these two assistance programs. The first row, set of rows on the table, is the discounted distribution rates. As I said, $6.4 million is being provided in discounted base rates. All customers in the other rate classes really pay for that benefit.
So the second row shows how the $6.4 million has been allocated to the various rate classes. The second set of rows we show the LIHEAP enhancement numbers. Again, what we're showing here is over that October 13 through September 14 period, $1.7 million of credits were provided to electric customers.

The equivalent on the gas side, just so you know, we look at this holistically as a total company program. $8.2 million was provided to gas customers in Rhode Island for a total of $9.9 million of benefit through this program.

As you can see on the electric side, the billings that we recovered through the various rate classes are shown. Obviously, A16, we have the most customers in that rate class. That rate class is deriving the most funding that goes into the fund. Any questions?

MR. WILSON-FRIAS: A16 is the distribution rate, right, not the whole bill?

MS. BURNS: Correct.

MR. WILSON-FRIAS: Do you know based on today's current overall charges to the A60 customers what their overall percentage discount is right now, say an average customer?

MS. BURNS: I don't know that off the top of my head. We could get it to you.

MR. WILSON-FRIAS: I'm just interested.

MS. BURNS: One of the concepts that we found with having a discount embedded in base rates, that as other rates change on the bill the percent of the discount can be diluted if rates go up, or it can increase as rates go down as compared to when the original discount was set in those base rates. It's very fluid. It will depend on the rate level at the time you do the analysis as well.

MR. WILSON-FRIAS: For example, if there is a high standard offer rate, the overall percentage discount would be lower than if there is a lower standard offer rate?

MS. BURNS: Correct.

MR. WILSON-FRIAS: That would be the same if transmission charges change and that sort of thing?

MS. BURNS: Correct.

MR. ROBERTI: Any questions? We're moving right along to renewable energy programs.

MS. LLOYD: That's me. Quickly before we move on, I just realized as Terry was going through this that I made a mistake on this LIHEAP enhancement chart.

It says we funded up to $10 million per year. I think it's actually funded up to $7 and-a-half million per year. It's up to $10 per customer per year. I'll fix that slide. We'll resend it to you before you post the presentation.

Now we go on to renewable energy programs. Again, on Slide 24 as with the distribution, I kind of broke out that typical bill and the annual dollar section that relates back to the slide that we went through originally. So you can see each of the programs that we have listed here. There are five separate programs. Each one of them has some form of renewable energy related to it.

The annual dollars, you can see in the particular column in total, based on the most recent years, these programs are worth about $28.9 million at this point in time. For each of those three customer classes you can see what that would amount to on a typical business basis on the customer's bill.

We'll go through each of these programs a little bit in the next few slides. On to Slide 25.

MR. NAULT: Before we move on to that slide, Slide 24 where it talks about the total renewable energy charges of $29 million, that's the cost to National Grid rate payers who are on the standard offer, correct?

MS. LLOYD: That's a good point. Some of these programs, the charges are assessed to all charges. So for example, long-term contracting net metering, other renewable fund charges, and the renewable energy growth program is new, so we don't really have a charge established. Those are charges that are assessed to all customers.

The renewable energy standard charge, our charge is only assessed to our standard offer service customers.

MR. NAULT: Competitive suppliers in the state are also subject to the same renewable energy standard?

MS. LLOYD: Correct.

MR. NAULT: Presumably some portion of what they charge their customers is a result of the renewable energy standard. Is there any analysis, documentation that would indicate what the total cost for Rhode Island rate payers is for these charges, what is paid through these charges on Grid's bill to its distribution customers and standard offer customers as well as the cost to customers who are taking competitive supply?

MS. LLOYD: I don't know that we developed any sort of analysis. Obviously, what each supplier, what it cost each supplier to obtain the RECs, or however they retain their renewable energy, would be to that particular supplier. I think it's something that would be difficult for us to estimate reliably without having that information.

MR. ROUGHAN: I'm aware that, fairly certainly that all entities in Rhode Island have to file something with the state to prove they're complying for the RPS, right? Somewhere in that report, I don't know where it goes in the state, somewhere in there, if there is any dollars and cents, that's where it would be available.

MR. ROBERTI: I believe it comes to us to ensure that we complied with the standard. But the cost, the acquisition cost of the RECs would be proprietary to each NPP. I guess that just leads me to question, in your mind would you expect that the cost, that standard offer customers versus the cost incurred by customers serviced by NPP, would you think that it's comparable between the two?

MS. LLOYD: I don't think I'm the one qualified to answer that. We all work in the same market. I guess that's about what I could say.

MR. ROBERTI: There is a broader -- the reason I ask that, there is a broader question about whether or not service from an NPP for your base energy versus service from National Grid through the standard offer program supervised by this Commission, are the ultimate energy costs seen by consumers comparable over some reasonable time frame?

I suppose that's the Holy Grail question that the state is going to wrestle with. It's certainly a

question in my mind. That's why I ask the question.
MR. LAFLAMME: What I would say, Paul, is the costs are probably comparable. What ultimately is included in the bill, I think as you point out, is very likely proprietary. We certainly don't have the ability.
MR. ELMER: Jeanne, could you clarify what this 810 figure in the bottom right-hand box represents? It doesn't correspond, does it, to the three figures to the left of it?
MS. LLOYD: No. What each of the three columns, the far right most columns is what the typical customer in each of those classes would be paying for each of these charges. So the $810 is what a typical G32 customer would pay in total for all of those charges.
It would be a customer that, you know, based upon the units that I've shown above, which would be 160,000 kilowatt hours and 400 KW.
MR. ELMER: The 409 is calibrated in millions, and the 2.53 and 5.06 are dollars?
MS. LLOYD: Yes.
MR. ELMER: Those correspond to the $810?
MS. LLOYD: Yes.
MR. ROBERTI: That's a per-month basis?

MS. LLOYD: Per month, yes.

MR. KEARNS: Follow-up. I believe outside of what Grid's costs are with the annual RES compliance, there is a lot of good information in the PUC renewable energy report that goes to the General Assembly. I believe some of that information may be in that report. I haven't looked at it in a year or so.

MR. WILSON-FRIAS: What we can obviously see is the level of alternative compliance payments made and the costs there. We can also look at each supplier and make sure they have met their required percentage.

What we don't see, unlike with National Grid where they file a renewable energy certificate procurement plan and all the associated costs through their RFPs, we can see it through the DG contracts, that sort of thing.

We don't have that piece of information for competitive suppliers, because, well, they're competitive suppliers and not regulated beyond having to meet certain standards. I think that's the one missing piece there that Alan was referring to.

MR. KEARNS: Under the charges, obviously, the renewable energy gross program is work in progress. You have the renewable energy gross charge, that charge is still pending. Replacing that program was the distributed generation standards contracts program. Is that factored into one of these line items?

MS. LLOYD: Long-term contracting charge recovers the cost associated with contracts procured through the long-term contracting program as well as the distributed generation standards program. That is both of those charges.

Let me go down quickly. That's what the long-term contracting charge recovers. Net metering charges recover the cost associated with paying net metering credits to regeneration. The renewable funds charge, this charge is actually embedded with the energy efficiency charge with our customers' bills.

I will go into that in a minute, what that is. The renewable energy standard charge, we already talked about. This is the charge that goes only to our standard offer customers. We'll get into that in a minute.

Then the renewable energy growth program is new, not yet approved by the Commission. That will live beyond the long-term contracting and DG standard program.

MS. BESSER: I know you already said something about the renewable energy standard charge. Could you say again what that is? Is that buying RECs?

MS. LLOYD: That's right. That's what Alan was referring to in the question.

MR. ROBERTI: The fact that the net metering cost is zero, does that mean none of the net metering customers exceeded 100 percent of their base usage, such that they would get compensation back from National Grid?

MS. LLOYD: There was some cost in the last reconciliation. For net metering customers, like our other long-term renewable customers, we sell the proceeds, the energy, not the RECs. But for net metering it's customers. In that reconciliation we look at the credits we paid to customers. We offset that from ISO from selling the energy. Then we recover the residual from customers.

In the last reconciliation the amount was too small for a charge. It was $50,000, or something like that. That's why it's zero.

MR. KEARNS: You have these charges broken out. For example, the DG contracts contract for, or the new tariff program, when we define the ceiling prices, that pulls incentives from the other programs. How do you make that distinction when you report the charges that rate payers pay?

Ultimately, whether it's the DG or the contract space program, the net metering or the RECs won't be pulled in as part of the subsidy that goes to either the contract or tariff. How do you make that distinction?

MS. LLOYD: Each of the programs and rate mechanisms have their own particular rules about what types of costs are included in the each of the mechanisms. Each of these programs has an individual tariff that supports it. It describes exactly how the charge is set and exactly which type of cost will be included in each mechanism.

Let's flip on to the next page. We'll discuss each one and maybe answer hopefully some of those questions. First program that we already referred to in --

MR. ELMER: Jeanne, can you clarify the origin of the three negative figures in the top line under the long-term contracting factor?

MS. LLOYD: Janet had referred to that earlier. Currently our long-term contracting charge is a credit. That's because when we set the charge in

November, for effect in January, we expected for the next six-month period, which is the length of time that charge is set, that the proceeds that we'll get from selling the RECs and the energy in the market will offset the cost or the payments we'll make under the contracts.

So for that particular period we expect these contracts to be below market. So that gave rise to the credit.

MR. ELMER: Is that an anomaly, or have we seen that before?

MR. SCIALABBA: I think we've seen it once before.

MS. LLOYD: It's somewhat seasonal, I guess. In this particular six-month period, we expect energy prices to be quite high. That's what gave rise to that.

MR. WILSON-FRIAS: Jeanne said we seem to see the credit often in the first six-month period and the charge in the second six-month period because of the energy charges. There is usually like two or three contracts that offset any of the above market contracts. So that's why we see the credit.

MR. LABEL: $700,000 in the first column, is that a gross cost, or should there be parentheses around that?

MS. LLOYD: That is a gross cost. The credit is based on the next six-month period. As Cindy said, one period might be below market. The next might be above. This is based on the most recent 12 months and doesn't necessarily line up with the 6-month credit period.

First program is the renewable energy standard program that we just referred to. For each of these renewable energy programs, the language of the purpose is somewhat similar as you would expect it would be. The purpose of all these programs is to facilitate the development of renewable resources.

This particular program, implemented a few years, requires providers of load in the state to acquire a certain percentage of their supply from renewable resources. That percent does increase every year. With Narragansett as the supplier, or the providers of standard offer service, we also have to comply with the statute.

For our part, the renewable energy supply as well as the standard offer, the method of procurement is part of our annual plan filing that we make every March 1. Once that plan is approved by the PUC, then we acquire RECs throughout the year in accordance with the provisions of that plan.

The charge, as we said, is only assessed to our commodity customers who are standard offer service customers. We set the actual rate or the charge every February. We do that by looking ahead to the upcoming program year.

We estimate what we think the cost will be in that program year. We also look backwards, do our annual reconciliation, look at the cost we incurred in the prior year. Compare that to the revenue we bill customers. That would affect a charge. Anything over/under is reflected to customers through this charge as well.

Also listed on the page, and even the pages that Mike referred to earlier, we tried to include the relevant statute, rule or tariff that applies. In this particular case this standard was generated, or originated from a statute, 29-39-26. We also, the costs are recovered through our standard offer provision, and the Commission has its rules governing the implementation of the standard.

MR. WILSON-FRIAS: Jeanne, you will be able to use at least -- let me start over. You could go out and get the RECs through RFP; they're a competitive supply. You also have available to you

RECs from the long-term contracts, or the distributed generation contracts; is that right?

MS. LLOYD: Yes.

MR. WILSON-FRIAS: So how do you account for the costs between distribution customers, from whom all of the costs are associated with the long-term contracts, and distributed generation contracts are recovered, and the renewable energy standard charges that are recovered only from standard offer customers?

MS. LLOYD: In the long-term contracting recovery mechanism, the cost, the primary cost that we incur are the payments that we make under the contracts that we execute. We offset that by the proceeds. Because as part of the bundled price that we pay for each contract, we get the title to the energy and the RECs for those that are produced pursuant to the contract.

So we incur the costs. We log that in our reconciliation. Then we offset that by whatever we get by selling the energy during the year to ISO. That credit comes from ISO itself.

For the RECs, we value those every quarter based on market information current at that particular point in time. That becomes a credit in the long-term contracting reconciliation, just like the sale of the energy. Simultaneously, we take that amount, and we include that as a cost in the standard offer reconciliation.

So all customers benefit from the credit through the long-term contracting mechanism. Standard offer customers pay the cost for acquiring those RECs as part of the standard offer adjustment factor.

MR. ROBERTI: You do the same with the capacity value for these contracts as well?

MS. LLOYD: If we get capacity through the contract, we do that as well. Capacity is a credit in that REC.

MR. ROBERTI: I thought typically under these long-term contracts you retain the right to all the attributes, including capacity, or is that not the case?

MS. LLOYD: I believe that's the case. I don't do the procurement of the contracts. I know we do not bid the capacity in every case.

MS. BESSER: Commissioner, I think on that point it's the utility's discretion as to whether they want the capacity product. Oftentimes, they don't take it.

MR. ELMER: I think that's under the DG

statute. I think under the long-term contracting statute you get the full bundled commodity, including the capacity. Then it's the utility's election whether to bid the capacity into the ISO auction.

MS. LLOYD: It is a bundled price for all of the products. I can't remember exactly how the statute is worded with what happens to it. Under the new statute, it is our option. I believe it is under the others as well.

MR. ROBERTI: Thanks, Mr. Elmer. If you get the capacity, just bid it in. That's all I'm asking.

MR. BIANCO: Some ISO rules would make that capacity not valuable. Some of your general operation characteristics, you wouldn't have a capacity obligation.

MS. LLOYD: Because of the intermittent nature of the generation. It's not as reliable on peak as some other types of generation.

MR. ROBERTI: ISO New England has developed, has made an assessment of what the capacity value is. It may not be 100 percent; it may not be 80 percent. It's actually pretty significant, both solar and wind, when you look at the resource contribution to meeting the capacity needs. I'll take whatever percentage that ISO allows.

MR. ELMER: What Mr. Bianco is referring to is the new redesign of the forward capacity market that the ISO has just put into effect for FCA9 next month, which puts a penalty for nonperformance for resources that acquire a capacity supply obligation and are not present when they're called upon.

Just to acknowledge that there is a controversy in the ISO as to the degree to which the FCM redesign will or will not penalize intermittent renewable resources going forward, there are different opinions about that question.

It is, Mr. Bianco is right, that that is an active question that renewable energy developers and owners have to grapple with in deciding whether to inquire a CSO in future auctions.

MR. ROBERTI: Thank you for that.

MS. LLOYD: All right. Moving on to the next mechanism, this we refer to as the renewable fund charge. This charge has been around for quite some time. It is statutory, like all of these charges.

As I indicated, this particular charge is embedded with the energy efficiency program charge on the bill. Customers do not see this as a line item on their bill. The statutory charge is .0003 dollars per kilowatt hours. That is assessed to all customers. The company bills customers for this.

We calculate the amount every month. We remit this to Commerce Rhode Island, which I believe is the Economic Development Corporation. It generates about $3.2 million annually -- sorry, $2.3.

MS. BESSER: Jeanne, this is reminding me that I forgot to ask my questions. On the other charges of renewables, how they are recovered from customers, whether they are kilowatt hour charges or also recovered through the kilowatt or customer charge?

MS. LLOYD: Back up to the renewable energy standard. This is a per kilowatt hour charge assessed to all customers on a, standard customers on a uniform basis. I'll indicate what they are as I go through. Same for the renewable fund, except this is assessed to all customers, and it is a per kilowatt hour charge.

MR. DESIMONE: I have a question. I don't know who it is directed to. From this charge, currently $2.3 million is generated from the rate payers, and those funds are transferred to Commerce Rhode Island?

MS. LLOYD: That's right.

MR. DESIMONE: Next question is, what does Commerce Rhode Island do with those funds?

MR. KEARNS: Renewable energy fund that Commerce gets annually is broken into different programs. There are different programs. One is, we amended the law in 2012 to allow homeowners the opportunity to participate in the program.

Prior to that, it was a policy decision that homeowners didn't have access to the funding. There is the residential solar program that is made available to all homeowners throughout the state. Funding provided to municipalities for feasibility studies for Work Like It, or connection studies, or permitting for projects.

There is also funding made available for start-up companies that are in the clean act renewable energy sector, and commercial solar is also eligible.

MR. ROBERTI: I have a question. You know, one of the intents of the legislature and the renewable energy growth program is to come up with equitable charges to be assessed to customer classes but also to have transparency and minimize customer confusion.

Even I, looking at my bill, sometimes get a little bit confused. This renewable fund charge, similar to the long-term contract charge, which also includes the distributed generation program charge, is assessed to all customers and is under the umbrella of renewable energy and not energy efficiency.

Is there anything in the statute that requires you to keep this within the energy efficiency charge rather than to have just a more generic line item for renewable programs that are assessed to all rate payers?

MS. LLOYD: Nothing that I know of. I think the law pertaining to the renewables and the energy efficiency charge came up at the same time. Originally there was a statutory energy efficiency charge as well. It was in the same section of law. I believe that's why they're originally lumped together. I think the law has changed since then.

I don't know of anything that necessarily keeps them together. It's simply the way we've been billing over the years.

MR. KEARNS: I can add to that. You have the energy efficiency charge and REFs are out of the same existing statute. I would assume that's why it's linked on the line item of the bill.

MR. DESIMONE: Perhaps this might be a good time to take a short break.

(BRIEF RECESS)

MR. DESIMONE: If the renewable fund charge was not embedded in the EE charge, do you know what that would be typically for an A16 customer on a monthly basis?

MS. LLOYD: I should be able to do that in my head. What's .0003 times 500? A penny and-a-half, one and-a-half cents.

MR. DESIMONE: Thank you.

MS. LLOYD: Continuing with the renewable section, we already talked about a lot of these. I'll try and go through them pretty quickly.

The next mechanism is one we already referred to several times, long-term contracting for renewable energy recovery factor. This does recover the costs associated with both the long-term contract executed under the long-term contracting statute and the distributed generation standard contract program.

These programs require the company to conduct periodic solicitation to, for these contracts for renewable generation. Both of these programs, the requirement to conduct the solicitation ended this year. Obviously, these are long-term contracts. We will still be incurring the cost for some time to come.

I sort of went into the way the recovery, or the costs are incurred and the way the factor is set. Essentially we make payments under the bundle price in each contract. We pay those contracts based on what the generator generates each billing period. We sell the products in the market. We get the proceeds for energy for ISO.

We value the RECs on a quarterly basis. Those become credits to the cost of payment, and customers pay whatever that above-market cost is. We set the rate twice a year, effective January 1 and July 1. We do an annual reconciliation where we look at the revenue bill to charge the actual cost incurred during the period.

The over/under is refunded or collected through the subsequent charge. Last year the over/under collection was about $2 and-a-half million. As we've seen, the charge is a credit, so that's offset for this particular period by the fact that this six-month period we expect many of the contracts to be below market. Any questions on that?

The net metering provision, we've had net metering in this state in some form for a long period of time. The law has changed several times in the last few years. Basically we pay a credit for customers, eligible customers under the net metering provision.

The law that gave rise to it is for the kilowatt hours that they generate in excess of what they may use for their own consumption. In addition to the renewable generation credits that we pay to customers who net meter, we also make payments to customers, what we call qualifying facility customers. We have a few of those. We pay what they generate at the standard offer rate.

All those costs are recovered, less any proceeds we get from selling the products.

MR. KEARNS: All the renewable energy funds that Commerce funds are all net meter projects?

MS. LLOYD: We do just sell the energy associated with these customers. The customers themselves retain the RECs under the net metering provision.

MR. ROUGHAN: The energy is sold for projects that are 60 kilowatts or larger. You do need hourly metering in order to be set up an asset. Because residential customers, the cost to that meter is substantially higher than the standard residential meter, we don't put in interval meters for those customers.

60 kilowatts and up is where we set up the asset and get that whole sale revenue back. The smaller ones actually aren't sold to the market.

MS. LLOYD: That's a good point. Thank you.

MS. BESSER: The last two factors you talked about, those are both kilowatt hour factors?

MS. LLOYD: Net metering charge is a kilowatt hour factor. Long-term contracting is also kilowatt hour. Uniform factor assessed to all customers.

The final, I'm not really going to talk about the final one, even though that is the reason that we have this docket to begin with, is the renewable energy growth program. That is a new law that was passed last year.

We are in the process of trying to implement the tariffs and the solicitation rules for that particular program. It has not been approved yet. We have made our filing in the proceedings. Tariffs are pending approval. We're in the discovery period right now.

We have a hearing in February with approval of the program expected by the end of March. The program will begin, assuming approval April 1 of this year. In a lot of ways the recovery, cost incurred and recovery of these costs are similar to the long-term contracting provision that currently we execute contracts with customers.

Under this particular program it will be tariff based. There wouldn't be any individual contracts. Each of the customers will be paid pursuant to the applicable tariff. It will be for a long period of time, up to 20 years. We will get title to the product. So in the same way that we sell energy and RECs through the long-term contracting program, we will do the same thing here.

Customers will pay for the net cost above whatever we get from the sale of the contracts along with certain administrative costs. The particular charge for this program, however, is expected to be a per customer charge. That was the mandate in the statute. It will not be a per kilowatt hour charge.

With that, I will turn it over to Jeremy.

MR. NEWBERGER: Thank you, Jeanne. On Slide 31, just to use the same format as the other components, you'll see the annual revenue in millions. That ties to Slide 8. The illustrative monthly bills for the various rate classes, that ties to Slide 10.

As seen on this slide, there are two components to these cost procurements that are charged to customers on their bill. One is energy efficiency, and the second is system reliability.

Slide 32, the energy efficiency profile, the basis of the energy efficiency charge is actually two points in the legislation that supports energy efficiency. One was decided from Chapter 79 of the general laws -- sorry, Section 39-1 of the general laws. The other is the same one as we referenced earlier about the renewable energy charge, 39-2-1.2. Both of those support energy efficiency.

Through the energy efficiency charge we develop a set of programs. We distribute the funds to customers in the forms of intensives, educational programs, technical assistance and so on. The charge itself is developed through an annual budgeting process where we look at the budget.

We look at what we have from other sources of funds, such as for capacity market and energy funds. We look at what is unspent or undercollected from the prior year. Then we use reconciling mechanisms to establish the charge for the coming year.

We make that as part of our filing to the Commission. Hopefully secure the Commission's approval for that charge. That shows up as the energy efficiency program charge on customers' bills.

So for the current year, current revenue, current period, we had overcollected in 2014. So we came into 2015 with a surplus. So the current revenue recovery is a combination of that overrecovery as well as new funds that we anticipate collecting throughout the year to support energy efficiency. To answer Janet's question, this is collected electronically on a per kilowatt basis.

The second component, on Slide 33 is for system reliability procurement. We use those funds to, right now to support our system reliability load pilot in Tiverton and Little Compton. It's a very small program. Our budget, our current revenue recovery for 2015 is half a million dollars.

That's cost procurement in a nutshell. Any questions about this part of the bill?

MR. ROBERTI: Any questions? I think that brings us to Mr. Zschokke. Am I right or wrong?

MR. ZSCHOKKE: So I'm going to talk a little bit about the rates. What you saw in Slide 36, we'll talk a little bit about the reason why they exists and how it all applies going forward. Not necessarily going forward, but right now in existence. We'll probably have other meetings to talk about going forward.

If you turn to Slide 35, you know, put your thumb or finger on Slide 6. You will see the revenue or charges associated with each one of these. Customer charges generally, in theory you want the customer charge to collect the costs that are associated with being a customer of the utility.

Those are generally the meter, the service drop, billing and customer service, those things that are required for customers specifically as opposed to things that are required for demand.

So the second element of cost is demand charges. Those are typically, we call it fixed cost, but really the demand. They're fixed in the sense of what we invest it in. They're fixed in the system in terms of capacity and cost. Then they depreciate, as you heard, on average over 33 years.

They're usually designed to collect those fixed costs relative to the size of the system we need to bill customers in our distribution transmission system. These are transformers, conductor poles, towers, substations, et cetera. These are really -- you know, in some sense a demand charge reflects the nature of how we need to design it based upon the size of the usage on the system, and what we need to design to, and the customers relative usage of that system.

The energy charges, usually energy charges are expected to recover costs that vary with usage. Whether it's an hourly basis, or monthly basis, or whatever, the resident standard offer service is the perfect example. We bid it out, get a price per kilowatt hour for providing that service.

Every kilowatt hour sold is charged that price. What we pay for that service is the same as what we charge customers. You know, kilowatt use goes down, standard offer costs go down. If they go up, standard offer costs goes up. It's one-for-one. Any questions?

Turning to Slide 36, you can go back to Slide 26, you can see the charges.

MR. ELMER: I'm confused on the variable charges that are attributable to the commodity. Can you discuss that? I mean, if we tie Slide 35 back to Slide 6, we're talking exclusively about the distribution side of the bill, not the commodity side the bill.

When you were describing it, you seemed to be talking some about kilowatts and commodity. So could you talk about the variable charges that are attributable to kilowatt hours that are not commodity?

MR. ZSCHOKKE: Historically the reason

why the small industrial C60 and A16 and A060 recovered distribution costs on a kilowatt basis is primarily because in the old days a demand meter was very expensive relative to the average cost of a residential customer bill.

It didn't make sense to put a demand meter on small customers' premises, because the cost of that would increase their bills too much relative to the value you would get from it. So you design kilowatt hours, because that was the cheapest meter.

You know, we can go into history, but I won't. That's been kind of a legacy with the industry in terms of that, is using kilowatt hours as a surrogate. Some utilities have moved to either demand base rates or size base rates, in terms of the amount of kilowatts you use, to determine what your charge would be on a monthly basis.

That's what, something we're thinking about as we go into this proceeding to reflect that, not so we have to change all the meters and cause that increase in cost, but that we can reflect sizes. You know, somebody who has a 3,000-square foot house needs more distribution capacity than somebody who has a 600-square foot apartment.

When you talk about creating a minimum bill, one of the big debates people have with minimum bills is -- I remember Wisconsin just recently, Madison Gas/Electric, you know, I'm stunned they did this. They filed for a $68 customer charge for residential class.

I don't know why they did that. I'll talk to the VP to find out why. Maybe it was an example. The reality is when you do that, you can see our typical bill on whatever slide it was, it's in a previous slide for residential. You know, that is a huge increase to the smaller customers in the class.

The question is, how do you move towards a size base rate to reflect the different costs that are contributed to the system by larger customers? That's some of the things we're thinking about.

Turning to Slide 36, we've already talked about the rate structure for A16 and CO6, customer charge, fixed monthly charge, volumetric per kilowatt charge. There is a minimum charge, which is the customer charge, and also for the CO6, some customers who need large capacity but are small users and are on the CO6 rate may actually be requested to pay an extra charge based upon the size of the transformer to serve them.

I think it's anything over 25 KBA. They would actually pay a fee for having that in order to recognize they're not a normal C6 customer, but they're using kilowatts as if they were.

The low-income residential rate does not have a customer charge as part of their discount. The kilowatt hour rate is resigned to provide a 50 percent discount.

We do have a standard watt hour metering. It is not an hourly meter. It reads, it sums up the usage over the month. Then we read it once a month with our drive-by vans.

Turning to Slide 37, general service rates for the medium and large CNI. This is where we introduce, as you saw in Slide 6, demand charge, minimum demand, 10 kilowatts, also a ratchet provision. For people who are unfamiliar with ratchets, it's a way of reflecting the size contribution to building the system and charging appropriately for customers who require a lot.

My example is, if I have two five-megawatt customers or five kilowatt customers, one uses it fifty hours a month and one uses it five hours a month, I still need five megawatts, even though they're not on the same feeder. The ratchet is a way of recovering costs from the five customer who uses it very little, but be able to pay their fair share of the cost for the distribution system. It will be equitable with the five megawatt customer who is using it an awful lot more in a year.

The result obviously is the per unit -- we look at it on a kilowatt basis. Per unit is more expensive for the five megawatt customer who uses it a few hours. And on a per kilowatt basis, the manufacturer, many hours of use, it will be much lower on a per kilowatt basis.

We do have a volumetric charge for the, to recover the remaining distribution charge. The preference would be to move them to a demand charge. These customers, particularly G30 and G62, they may take service at primary voltage or higher, 115 KV. If they do, we don't allocate the cost of the secondary system, which is primarily for smaller customers.

The primary system, they're served at 115 KV, so they get a discount for high voltage metering and service, if they so qualify. For the larger customers, G32 and G62, for all of the commercial industrials, the metering records demand in kilowatts, and then the hourly, then the kilowatt hourly usage.

The largest customers on the backup rates as well as the general service rates have hourly interval meters. Actually, it's interval meters that record on a 15-minute basis updated every 5 minutes, I think. Any questions on this?

MR. WILSON-FRIAS: What does the interval meter show you when you're reading that meter versus the regular meter?

MR. ZSCHOKKE: The meter for the small customer, just that one, what they call a register, that register just accumulates the usage as it goes on. In the old meters before we went to the drive-by technology, you would see the wheel spinning. So it's the same thing. Just recording and adding up every kilowatt of usage over the hours until the end of the month when we read it.

The interval meters, they actually read and store, so they have memory in the meter. They store an observation every fifteen minutes -- is it five minutes? Five minutes. So that when it comes into the system, we can then determine what their actual usage is. You could actually pull out a lot more detailed information from those customers.

MR. ROBERTI: The demand versus the consumption?

MR. ZSCHOKKE: If you're getting it every five minutes, you would add it up to the fifteen minutes. You would determine what the highest fifteen minutes would be through the demand, through the month. So it's 720 times 20 times an hour. 720 hours in a month, times 20 observations per hour, you would be getting all that information. You would sum across to determine how much kilowatt usage they had.

For G30 you would sum the different periods as well. You would split it out. It's far more granular data, far more detail when you use it and when their maximum demand is.

MR. LABEL: Demand charges are based on 15 minute demands and not non-coincident peaks for that one customer?

MR. ZSCHOKKE: Based on actual demand, which you would call -- I won't get into that just yet. You know, the issue of diversity of demand always comes up. What people need to remember is we have a cost of service that says we have to collect X. If the diversity is smaller, obviously the per unit charge is higher.

If we were to measure the individual demands at the time of the peak, discuss whether it should be one hour or many hours, you would come up with one number. Obviously, it was people's time at the peak, which is what the ISO New England does. If you actually -- however, that's a higher number than if I use everybody non-coincident peak. The value of diversity gets spread across all customers, because you're using the non-coincident peak.

The rate per units is much lower than if I was doing it on one-hour peaks or 700 hour peaks, whatever you would think about in terms of designing it in that way. That has a lot of customer impact issues if you change the way you do it. From my professional experience, you know, customers looking at the demand and seeing my cost is 100 kilowatts, and I know when it happened, and I know that if I lower to 90 I save money, great.

It's a lot more difficult question, discussion when you come back at the end of the month, and you say, By the way, at 2:00 on this day you used X. That's what your bill is for. From my discussions with many customers over the years, that's a really hard discussion. I can only say that much. Any other questions?

Back-up service rates. For the rate -- I'm going to say I hate the term back-up service. Utility industry has used it for years. It's a standard. That's what our tariffs are called.

I differentiate between generation, transmission and distribution. So generation, there is a lot of diversity around the diversity system. You have generators to call on, transmission systems that deliver all over the place. Bulk generation, not local generation.

A customer whose generator goes out, how does it affect the ISO New England? Well, ISO has lots of customers moving around. They will always have generations they can pull forward. I have a feeder that has so much capacity; I have a substation that is feeding that which has so much capacity. I only have so much flexibility.

There is a lot of generation on the line. I have some issues with generators coming on and off. I don't have the flexibility ISO has. I agree, there is great, at the wholesale level there is a lot of opportunities for diversity in terms of how customers come on and off the system with generation.

At the distribution level, though, it's a much more distinct problem for our engineers to understand how much flexibility they can or cannot have with generation. I say that knowing that both in the system reliabilities plan we're trying to bring in solar to see how that works with managing peak loads in the Tiverton-Little Compton area, along with what we're doing on the air conditioning side and direct load control.

Also in our solar phase two filing, which was approved in Massachusetts where we're actually going out and investing in solar facilities behind the meters with advanced inverters to see how advanced inverters can work. If we turn them westward, whether or not they will be on at the time of the peak. What is the value in that?

The reality is an unconstrained generator on the system. We have an issue with, will it provide the value/not provide the value; what are we backing up for the customer?

I do want to point out that today we actually have a rate called the second feeder service rate. This is my example. The second feeder service rate, which in the last six months, I have looked at sanction papers for investment to connect the customer where they actually requested additional amounts of second feeder service. We reserve capacity on a line on a second feeder for the customer that we do not use for anyone else.

When they do their planning studies, they come in and say, I need additional capacity in this area, because this customer is being fed off one line, but they also want nine megawatts off another line. That is not available to any other customer, because they're paying a second feeder service rate.

What that gives the customer is the right to flop over automatically to another feeder if they have an event on the first feeder. It's for customers who have high reliability requirements. Making sure they can be served immediately if there is an event on the first feeder, that they do not lose continuous flow.

I look at back-up rates on the distribution level in the same manner. What if that required the utility to provide service to customers who may have generation behind the meter that may or may not turn off at some point in time? How flexible are they in controlling that, or what control they give to the utility?

To me, it's like insurance. We all buy insurance for our houses. We hope we never use it. We determine how much level, what is the level of insurance we want. What do we want to cover; how much do we want to pay? We make those decisions.

In some sense, back-up rates should be designed to do the same thing. Let the customer pick their level of service. If you want 24/7 automatic access, you should pay a higher price. You only want nights and weekends and you're willing to control your use of the grid in order to get that --

I begin the discussion with that introduction here. People can put it in the framework of distribution as opposed to the system as a whole in terms of the electric system as a whole. There is a cost. Our engineers are, they're required to provide service. We have service quality standards. If something happens in a sensitive area, we're called on the carpet.

Their job is to make sure that wires stay up; that the customers are served. Reliability meets the standards set as part of the state. We are, there is a cost to owning and maintaining facilities that maintains that service. I would also point out that the rates we have in effect today and the system we have built today is only one way. Right? We built it based upon one-way service to customers to load at the end.

What we're seeing now with distributed generation on the distribution system is that we now have to build a two-way system. It will be completely different. A lot of things will look the same. A lot more control, a lot more communication, a lot more stuff we'll need to understand. As the engineers point out, maintain the stability of the system.

So because stability of frequency and voltage are the most important things that the engineers worry about, voltage is too high, bad things happen. Voltage is too low, things don't work. Frequency out of bounds, the system falls flat. Those are things people worry about.

When you put a generation on a system not designed to handle it, then you have issues we have to deal with. Back-up service rates are a means to kind of fairly allocate costs to customers that have generation so that they're paying their fair share of the distribution service.

The additional facilities, we need to actually manage this as it comes onto the grid, because it's more and more prevalent. They're an essential element. That's why we have them here. Right now net metering customers are exempt from those rates.

As we move away from net metering, because it is a promotional element to develop the business, we should be able to see rates that actually charge customers for the services they receive, but also pay customers if they get, if they provide services back from their generation.

Any questions ? I just said a lot.

MR. ROBERTI: You ended on the most

important topic this Commission is charged to do under the law. So any questions? You have one more slide here.

MR. ZSCHOKKE: This summarizes what the back-up service rates are for nonrenewable generation. B32, B62, mandatory for customers with nonrenewable generation of 25 kilowatts, they have an assumption set at 10 percent of full requirements, distribution demand charge. There is an assumption of 10 percent coincident factor, meaning coincident with the distribution company peak.

They would only be coincident about 10 percent of the time. I don't know how that was derived. I'll certainly find out more as we go forward.

There is also a combined heat and power provision on these, customers who actually receive energy efficiency incentives to put in this system. They're not eligible for back-up rates, but they do have special rates applied to them, including a minimum demand charge, to make sure they're paying their fair share after being given such a healthy benefit from the energy efficiency program. It's a way of making sure they pay their fair share of the grid.

MR. NEWBERGER: That they're not getting over-incentives for combined heat and power.

MR. ZSCHOKKE: Right, getting incented (sic) twice. Any questions on that?

MS. LLOYD: We're not going to do Slide 40. Slide 40 was an attempt at saying here are some of the goals of the various, some of the goals of the state, the company, and how does the rate mechanism on the right-hand side of this chart satisfy some of these various goals.

It's sort of a, something to maybe generate further discussion in the future. I put it as a concluding item to the presentation.

MR. ROBERTI: Any questions? I know there are a lot of people in the back of the room. I want to offer an opportunity for anybody to make any comments or ask any questions. Any questions? No, okay.

MS. BESSER: Thank you, Commissioner. This has been really helpful to lay things out. I wanted to ask what is really maybe a general question, not about the specifics here, but as you look at Slide 8 and you look at the distribution of the categories, costs recovered or costs incurred -- actually, I'm looking at revenue columns.

The question I have, I'm trying to figure out if it's this one. For example -- actually, it's all together. Here is my question: How often does the ISR number get bigger or smaller? Right now it's quite small relative to the distribution charge. Does that affect which customers it's being recovered from?

I think I'm answering my own question. I think you said the ISR is the one charge that is rate designed. It's not a kilowatt hour pass through.

MR. LAFLAMME: I can answer that. It was something I should have mentioned. The ISR charge gets rolled into base rates at the time of the rate case. We actually did roll in some of our previous, because it is recovery of rate base. So once we, once we file to establish new base rates, the then cumulative amount of investments that are being collected in the ISR just become part of our rate base.

MS. BESSER: Reconciling mechanism between rate case.

MR. LAFLAMME: Exactly.

MR. HANDY: I have a question about the ISR. It sounded like a lot of it was focussed on vegetation management, a large majority of it. I'm wondering how depreciation works in that context. Is it the cost of equipment, or how it depreciates relative to vegetation management?

MR. LAFLAMME: Two components to ISR, IMR, or expense component. The biggest piece is vegetation management. All of our operating expenses are recovered. They're dollar-for-dollar. The depreciation is purely on investment in our system.

MR. BIANCO: I appreciate it. I was running in and out, but we have speakers in our offices. I was listening. I think it was very useful.

I kind of thought a lot more of the presentation, I didn't have a chance to look at it, would actually be Slide 40, not to look over the fact that it was a very useful presentation. We were talking about some of these overlapping programs, and a lot of the people were, that are here today were in a meeting where we sort of started drawing out everyone's understanding of how things overlapped.

I mean, from the Commission's point of view, direction of the company and how it plans to use these different programs to achieve these goals, and also our point of view, there are different rates of return in some of these programs. Some have remuneration, some have performance incentives, and some have regular rate base returns.

Actually, that is the thing that I'm more interested in learning about, specifically what the overlap is of ISR and SRP and energy efficiency. If you guys have any more direction on how, more information on the direction that, you know, the company is planning to go with some of these programs that overlap, and how you plan to divvy up the different costs into SRP, for example, and ISR, I would like to hear about it.

MR. WILSON-FRIAS: I think just, Todd, to give a little more background. When we started planning this, I think you're right. This is a lot of what, this slide is a lot of what we talked about at the first planning meeting as National Grid got into trying to develop the presentation.

MR. BIANCO: I appreciate it.

MR. WILSON-FRIAS: They called me and said, This is going to be six or eight hours long. So we decided, and I probably didn't circle around, but we decided to start with this thinking that questions that came up today, and even like this would lead into sort of what is the next, what is the next meeting, what is the next presentation maybe going to be.

I think that is a really good point. I think it's important. I just wanted to let you know that they weren't not listening to what we said to them.

MR. BIANCO: I just was wondering if we could hear anything on that today. If there is direction there yet, or if that's something that you are still figuring out?

MR. LAFLAMME: I can take a stab. I'm not sure I'm understanding.

MR. BIANCO: Let's take a project, if you have a Volt VAR program, I could imagine that there are -- well, if you had a really good one, there might be an OMM cost, but there could be. Those could possibly go into an energy efficiency program. If it was in ISR, you wouldn't receive any kind of return on that investment, right? It's just, it's not a capital expenditure? You get a rate base return on OMM?

MR. ZSCHOKKE: As the asset place is in service.

MR. BIANCO: Like an operation standpoint, I mean. It's not planned. The part that is planned could go into ISR. The part that is not could maybe reasonably go into an energy efficiency program where you normally wouldn't earn a planned return on that. Could you earn a return on it through an energy efficiency program? I'm wondering if any of that has been mapped out.

MR. LAFLAMME: Typically we try to keep

like-type costs together. As Jeanne pointed out earlier, we do have tariffs that specifically define what that charge is intended to recover. Clearly as time goes on, things get a little fragmented.

As we talked about today, there is a renewable charge in our energy efficiency charge, I think, simply because it was borne out of the same legislation years ago.

I think typically our intent would be to isolate like charges in a same type charge. I think over time perhaps they got a little fragmented. We take extreme measures to ensure that we are not double recovering anything.

You know, the Volt VAR recovery that we have in ISR was really kind of more of a pilot-type thing. If, indeed, there was a desire to have an energy efficiency program to address that, we would include it in energy efficiency and absolutely not charge for any costs associated with that program in our ISR.

I think as time goes on and as things are fleshed out and developed, our intent would certainly be to charge like-type services in a similar charge.

MR. BIANCO: Thanks. That is better than a stab. I appreciate that.

MR. ZSCHOKKE: We talked about this,

because people do argue about Volt VAR, whether it's an energy efficiency program or grid program. We consider them to be both. We do it now. We just don't do it with the sophisticated tools that are available today.

Really the separation that Mike talked about, energy efficiency is for programs that are delivered to customers. So you're paying customer rebates to do something. As long as you have programs available to use the funds there that can contribute benefit to customers, keep them there. Then use the ISR to do things like Volt VAR which may provide energy efficiency benefits by managing the voltage on the system.

I will be very careful. They will be measuring it, so we will be able to determine it. You would also recognize the fact that Volt VAR does more than just provide energy efficiency benefits. It helps to manage the stability of the system that I talked about earlier, the frequency and the voltage management there, which we have to do anyway.

It's more than just energy efficiency when you think about it from the grid operations perspective.

MR. BIANCO: I think, too, Counsel, if you're planning on having more meetings to hear more about these, that would be great.

MR. ROBERTI: We were talking about, we can talk about are there any next steps before the July 1 filing.

MS. BESSER: I think Mike just said something that I want to follow on today's point, because I think it was a good one. If the company were to be ramping up a Volt VAR program, it might end up an energy efficiency program where costs are recovered on the kilowatt basis versus ISR program.

One of the things we talked about in the initial meeting, thinking ahead to the end point of all this, which is a rate design filing, that is to try to recover costs equitably from all customers and not in any way to undermine the objectives the legislation that is promoting renewable, et cetera, et cetera, the State of Rhode Island is promoting.

So the question I have, as some of these categories ramp up, it strikes me that it will matter in terms of the allocation. I was going to say distribution, but I don't want to be confusing. Allocation effects on different customers.

For example, a Volt VAR in the ISR will have an effect for large industrial and Volt VAR recovered through energy efficiency, which is a kilowatt hour charge, which would have a different impact on large customers. I think it would be helpful, Cindy, if we're thinking about next steps and next meetings to actually maybe play out some scenarios, because it strikes me that some of these categories matter.

One of the things I was struck by is that SRP is in the energy efficiency program. SRP, if I'm recalling correctly, things like the Tiverton pilot, distributed generation pilot.

MR. ZSCHOKKE: Direct load control pilot that we're contemplating adding solar to it as well.

MS. BESSER: If you're adding solar to that or making that kind of investment either with the energy efficiency program or broadly under the growth program, some of the impacts of which category those costs are recovered in might matter. That's the kind of scenario that I think will be useful to understand better.

I know that's a really vague request. It's almost like play out some scenarios, put costs in different buckets and see what the impact is.

MR. ZSCHOKKE: If the person from Tech RI, they want things allocated on a demand basis than energy basis, we did Volt Var under energy basis.

MS. BESSER: They would pay more.

MR. ZSCHOKKE: May or may not get the benefits, because they may not be served at the feeder level. That would be, we would have a nice discussion about that.

MS. BESSER: It would be interesting to see what the differing impacts are.

MR. NEWBERGER: Just to clarify a couple of things, firstly, SRP is not part of energy efficiency. It is part of energy efficiency on the bill. It's part of the lease part procurement. That is the umbrella name for everything.

System reliability, some of us around the table know it has taken a long time. What took a long time for it to become defined and what it's defined as right now is this pilot, as Peter described, the load management pilot for Tiverton and Little Compton.

There are a number of different technologies being looked at through that pilot. The general premise of your question is correct, Janet, that it's possible that some of those technologies will prove out and will be developed and deployed in a larger scale.

It's a fair question to ask. Where, you know, where those would end up. Some of them may be more customer side, and some of them may be more grid side.

I think that is a fair thing to explore. Right now the pilot is defined as load management pilot. It is run through, run as a pilot, and the charges lump together with the energy efficiency charge on the customer bill.

MR. ROBERTI: Any other questions? Are there any next steps we need to talk about? I know we have the July 1 deadline approaching for the filing of the proposal.

MR. WILSON-FRIAS: We had the first meeting at the staff level with the people sitting around the room and many others that might be in the audience and tried to outline where to start. We wanted to start with getting an overview of what the rates look like.

Todd and I have a meeting with OER early next week to see what they're working on that might overlap with what we're going to need to think about going forward, to see if there might be some other presentations and what topics are out there, they've already being worked on.

I think Janet made some good points. Todd made good points. We're probably going to have another meeting at the staff level to sort of take, to play out what is going to happen, try to get some dates on people's calendar and figure out where to fill them in, in order to give the Commission as much background as it has before going into that July 1 docket.

MR. ROBERTI: Thank you. Are there any concluding remarks by anybody?

MS. GOLD: I think it's really valuable to have all of us sitting here sharing information. As I leaned over and said to Chris, when the renewable energy growth program was started as a pilot, the comment was we had this very well organized, incredibly well thought-out program on the efficiency side of the house, but the renewable energy side of the house was disjointed incrementally.

I was struck again today. The way we're treating renewable energy is complicated. As I watch the growth program emerge and the tariffs, I see it's getting more disjointed and not less. I'm concerned when I look at it from both a greenhouse gas emission reduction and a cost side, because given the high and volatile energy prices, this should be an opportunity for more to use local clean edge energy as a hedge against volatile energy prices.

If the costs keep going up, because we haven't thought it through together, we're going to have a problem. I think this is a really important first step. It's very complicated.

The other comment that Chris made is there are a lot of folks from National Grid here who spend all their time thinking about these issues. You guys accept we're juggling a lot, including, you know, how do we fit transportation into the scenario in a way that works for the utility as well as for the public sector. This is a good start.

I think it's really important that, you know, the 30, 40 people that think about these issues get together and share information. We're looking forward to sharing the partnership with the utility.

Something that will move us forward steadily, I said this many times, we hope to build on the experiences you have and some of our colleagues here have had in other states. What lessons can we take from what is going on in New York, and Massachusetts, and God forbid, even California, and bring them here in a way that works for you and build our economy.

Again, that is certainly an important priority. We are kicking off the solarized program in Little Compton-Tiverton on Monday with the Governor and Senator. The message is, how can we bring clean energy not only to benefit homeowners and businesses, but how can we use it to reduce overall system costs?

It seems to be working there, though we won't know for a few years.

Can we take the lessons we're learning there and apply them throughout the grid shed, whatever, water shed of the electricity, of the electricity system? I really appreciate you, Cindy, bringing us together and look forward to grappling with these complicated issues.

MR. ROBERTI: If necessary, the Commission can convene more sessions like this. We're willing to do that. I want to ask Commissioner DeSimone if you have anything you want to say before we close this open meeting?

MR. DESIMONE: We have nothing to learn from the great State of Michigan?

MS. GOLD: We're coming up from a low point in Michigan, but yes, that's a good question.

MR. ROBERTI: Any other comment?

MS. O'BRIEN: I just wanted to thank the Commission and the parties who have attended this meeting, as well as the prior one we had a couple of weeks ago. We thought this was a good introduction to starting the discussion, given how many people are interested in this, you know, sort of predocket.

We wanted to get before you sooner rather than later to provide this kind of level setting for everyone on what we currently have in place. That will start generating more detailed discussion that will certainly lead naturally into what we ultimately discuss, what the rate design and cost allocation docket is. Again, I appreciate the opportunity and look forward to more meetings like this one.

MR. ROBERTI: Thank you, Ms. O'Brien. I think the presentations were very instructive and provide a very good first step for this long path we're on in the next year. I want to thank National Grid for the presentations and everybody else for their attendance and participation. If there is nothing else, we'll stand adjourned.

(HEARING CLOSED AT 3:45 P.M.)

C-E-R-T-I-F-I-C-A-T-E

I, ELIZABETH GREELEY, a Notary Public, do hereby certify that I reported in shorthand the foregoing proceedings,and that the foregoing transcript contains a true, accurate, and complete record of the proceedings at the above-entitled hearing.

Reading and signing of the transcript was not requested by any parties involved upon completion of the hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 29th day of January, 2015.

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ELIZABETH GREELEY, NOTARY PUBLIC
CERTIFIED COURT REPORTER
MY COMMISSION EXPIRES: 04/07/2018

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