COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2020-00174

VOLUME V

Transcript of November 23, 2020, hearing before Chairman Michael J. Schmitt at the Kentucky Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, with Vice Chairman Kent A. Chandler, Commissioner Talina R. Mathews, counsel, and witnesses attending via GoToMeeting.

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Ms. Candace Sacre, PSC Court Reporter

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(Hearing commenced at 9:09 a.m.)

CHAIRMAN SCHMITT: Good morning. We are now back on the record.

And I think when we recessed Friday afternoon, Mr. Spenard, you were in the midst of your cross-examination of Mr. Vaughan; is that correct?

MR. SPENARD: Yes, Mr. Chairman. Good morning.

CHAIRMAN SCHMITT: Good morning. Do you still have questions of Mr. Vaughan?

MR. SPENARD: Yes, Mr. Chairman.

CHAIRMAN SCHMITT: All right. Ms. Blend, are you with us, and is Mr. Vaughan ready to retake the witness stand?

MS. BLEND: Yes, Your Honor, we're here and we're ready to resume. Thank you.

CHAIRMAN SCHMITT: Thank you.

Mr. Vaughan, you remain under oath and Mr. Spenard will continue his cross-examination.

All right. Mr. Spenard, you may continue.

MR. SPENARD: Thank you.

* * *

ALEX E. VAUGHAN, having been reminded of his oath, testified as follows:

CONTINUED CROSS-EXAMINATION

By Mr. Spenard:

Q. And welcome back, Mr. Vaughan. In terms of trying to get on the same page again from our discussion on Friday, there can be -- in your opinion, there can be a difference between average usage and peak usage for a residential customer; is that correct?

A. Yeah. Average is just the average amount used over some period of time, the peak being the most -- the highest amount used in some measure, whether it's coincident, noncoincident, generation, transmission, or distribution. It would be the maximum figure versus an average.

Q. And in terms of aggregating the customers together in a class, using your -- using your discussion, there could be a difference between the average usage for the class and peak usage for the class; is that correct?

A. Could you say that again?

Q. In terms of aggregating the customers within a class, when you aggregate their numbers together, there can be a difference between the average usage

for the class and the peak usage for the class?
A. Of the individual customers in the class, yes, but the average for the class and peak for the class are just that, it's the figures for that class, and you don't -- you don't aggregate customers based on averages or peaks, generally. Some industrial tariffs are load factor differentiated, but generally you're taking similarly-situated homogeneous customers, like all the residential customers or all the small general service or all the general service, and you're putting those like customers in a class and then using that as the basis for your class cost of service.
Q. Okay. And again, that was -- that was actually the question. We're talking about average usage for the class and peak usage for the class.

Is there a peak associated with generation production, for example?
A. Yes, as I -- as I mentioned, you have generation production peaks. You have transmission peaks. You have distribution peaks, primary and secondary. I think that's most of them. And then whether -- well, that's from the Company's standpoint. And you also have PJM peaks that we

deal with. So there's a great, great number of peaks that factor into cost causation and cost assignment.

Q. Sure. And that's fine. And I think the Commission wants to have a comprehensive record, and some of your answers are really things that need to be focused upon, if they need to be focused upon at all, redirect. And for purposes of cross-examination, let's at least just highlight or try to stay focused on the particular question I'm asking than to anticipate what I might ask, because it might go a little -- it might go a little faster that way.

In terms of definition, is it fair to characterize the peak period as the period that -- for generation production, is it fair to characterize the peak period as the period that corresponds with the highest iteration production on the Company's system?

A. No.

Q. Okay. And why not?

A. Well, it -- the generation peak is when the Company's load is highest based on what is causing the -- you know, well, what is the cost causer for generation? You know, in our -- in the Company's

position, it would be the PJM summer 5CPs. It's not when the most generation of the Company is running. That's irrelevant. It's a matter of what causes your generation capacity obligation or expense.

Q. Okay. Well, in that comprehensive view, to the extent that the peak usage associated with that capacity is in excess of average usage associated with that capacity, does that reflect an increase in the cost of service for that customer class?

A. Can you say it again? You're confusing me a little bit with your peak and average discussion.

Q. Okay. Well, my understanding of what we've been talking about is that if you take a look at a customer class, if you look at their results for the class, for whatever period of time, you're going to have -- you put them all together and then you can derive an average of what their usage is, their average usage for the period, but then also, when you look at that customer class, you might have a period that the average -- sometimes there are observations below the average, sometimes observations above the average. There's going to be an observation that's above that average that's the peak; is that correct?

A. Yeah. By definition, the peak is higher than

the average, and the average takes into account all hours in whatever period you're measuring.

Q. So when we're talking about the impact of that peak, how -- what -- how that peak of the many things that that peak will do, and it might do a lot of different things, but is one of the things that that peak will do, will it actually reflect an increase in the cost to serve that customer class?

A. So it depends if you're -- if you're talking marginally or from an incentive standpoint. It's the basis for the overall cost, and it's only going to be an increase in cost if the peak contribution is large enough to cause the Company to have to incur an additional incremental cost, whether that be -- we're talking generation, so it might be we'd have to go purchase some capacity from a sister company or from the market or at an asset.

Then you can look at that from a marginal standpoint, say, look, that that incremental peak caused incremental cost. Otherwise your -- if you are capacity sufficient from a generation standpoint and you are evaluating the peaks, it's generally how you are then spreading those costs, but it's the basis for cost and causation.

Q. With regard to when a customer -- when a

customer in a class shifts load away from peak periods, is that one way to lower peak usage within that class?

A. Again, we have to go back to the discussion we had on Friday. You have cost-causing, which is in the overall revenue requirement. You know, what -- are we avoiding something or are we adding something from a cost standpoint? And then you have to go look at cost assignment within the class.

And so when a customer reduces its peak load -- again, we'll just stay with the generation concept. If a customer reduces the 5CPs, there is potentially a reduction in generation capacity cost for the Company, either through, you know, a reduction in cost, or maybe, if the Company is long, it can make an incremental sale of length into the market. So there's some value there. And so that's from an overall revenue-requirement/cost-of-service standpoint.

Then once you get into that class, there is no reduction in cost. Once you've established the total basis of cost of service for the Kentucky retail jurisdiction, you're then just shifting costs between customer classes. There's no actual decremental cost in your example.

Q. And is that for -- is that for one period or is that for the long term, over the long run of, say, whether you're talking about -- is that going to hold for the next month or does that hold for the next 12 months or does that hold for the next 12 years? Are you saying that there's never going to be any shifts within the class over any period of time?

A. So your question mischaracterized my statement. There will be shifts within the classes, but you're not reducing overall costs. Once you have reduced overall costs in the overall revenue requirement, the overall cost of service -- we've already established that in the ratemaking process. Before we even move into the discussion of classes, we're determining the total cost of service. And what I'm saying is, when you have certain peak reductions, you can lower the overall cost of service, and that's what we've accounted for in our avoided-cost rates in NMS II.

So then after you -- you get past that, you have a total amount of cost of service, which includes the value of those peak reductions. You then go to the class stand -- the class state of rate design and this whole process. And at that

point there's no further reduction in cost, there's only shifting.

You know, in this case, the base rate revenue requirement was $70 million, if you look at the Section 5 summary schedules. And so once you have your $70 million, which includes cost decreases from load reductions, if they were on the peaks, that 70 million stays 70 million in the class study, it's just a matter of how it gets shifted between the classes to recover it.

Q. Will the cost of service change from year to year and, in turn, from case to case?

A. Absolutely. And that's why we did the study we did and proposed the avoided-cost rates that we did. We're fully valuing those load reductions in that.

Q. With regard to the test year, did Kentucky Power Company use time-of-use meters for customers receiving service under the Net Metering Service I tariff?

A. No, we didn't. And kind of whatever happened to the NMS I customers in the test year doesn't really play into this, since they are grandfathered under the Net Metering Act.

Q. Well, that's fine. With regard to the test

period, did Kentucky Power Company support the test period with a demand study or otherwise develop a load study for its customers taking service under the NMS I tariff?

A. Yeah. It's in Mr. Stegall's -- excuse me. Yes, it's in Mr. Stegall's work papers. Because they are residential customers, they are part of the residential class.

And as I discussed in my rebuttal, you do not need to have a separate load research study for every component of a class we have with -- you know, to make just and reasonable rates. You know, we do not do separate load research for RS-TOD, for load management, water heating customers. We don't do it for general service athletic fields.

You know, you do the major class, because, again, all of those customers, the underlying loads are roughly the same. They're not special just because -- from a load standpoint, because they chose some behavior other than or different from the rest of the class.

Q. Well, perhaps we can wrap this up with just -- this particular section, with just a few more questions, then, just so I can confirm my understanding. Kentucky Power -- did Kentucky Power

Company study when the distributed generation delivery is going into -- from the NMS tariff customers, when their distributed generation delivery is moving into the Kentucky Power system as compared to when the Kentucky Power system is hitting its peak?

A. Bear with me for a moment.

Q. Sure.

A. So the answer to your question is yes. And we looked at that both on -- in my direct testimony, which would be AEP Exhibit 3 that shows the residential customer -- residential class profile by hour compared to the generation shape in the Company's service territory for solar generation. And that doesn't change. It's the same generation shape there as it is across the state line in Virginia as it is up in West Virginia. It's a regional thing. The sun tracks across the sky in roughly the same manner.

And then again in rebuttal, on R38, I point you to down there on line 18, we do -- Kentucky Power's affiliate directly across the state line in Virginia actually was ordered to do a study with full interval meters on it, its distributed generation solar customers in the residential class.

And what that study and those graphs show is that at the peak time, the load shapes are exactly identical between the load -- between a net metering customer and its other residential customer, as you would assume, because they're all residential customers. The only difference is when that system is putting generation, you know, either netting out the customer's load behind the meter or putting generation back out into the Company's distribution system. And again, that is what we've accounted for in our studies and analysis here, and that's what we've included in the avoided-cost rates of NMS II.

Q. For the NMS II tariff, will the proposal incentivize distributed generation customers to lower their cost of service, so lower the activity that they have that's leading to any peaks in the Kentucky Power system?

A. I don't -- I don't think so because it's the same standard residential rate they would be paying for their net load, you know, as any other residential customer. So to the extent there is a price signal there, it's the same for all residential customers.

The incentives with NMS II would be for customers to, you know, maintain and keep their

systems running, because they're being paid for their excess generation beyond what is actually netting their load behind their meter at a -- at the avoided-cost rate. You know, that's -- that would be the price signal in that tariff.

Q. So with regard to that price signal, what is the effective rate that a distributed generation customer would pay under the proposed NMS II tariff?

A. I have that. Just a moment. And so if you look at Vaughan Rebuttal R41, starting on line 3, there's a couple tables in here discussing what a typical residential customer and system would see and what a typical commercial customer in the DG system would see. And so, like for residential, if you follow across there, based on test year data, a typical NMS bill would be $35, where a standard tariff for the same customer would be 166, and then -- this is at proposed rates.

And then under NMS II, the customer would be charged a hundred dollars for their usage, and they receive a $19 excess energy credit, so they would have a net bill of $81. So at 1,240 kilowatt hours, they're essentially -- you know, they're paying, all in, seven cents a kilowatt hour versus, you know, closer to 11, 12 there under retail.

Q. Okay. With the proposed rollout of AMI, if that is approved, how will the NMS II tariff be impacted by the rollout of AMI?

A. Well, I don't think it would be impacted at all right now. I mean, whatever the Commission approves would be in place until the Company came in and had another rate case. At that time you could consider changes to whatever is approved at that time. You know, the -- to leverage more off the AMI meters or -- I mean, it's just metering. We have to meter the customers. So whatever our prevailing meter technology is, NMS II customers will have that.

Q. And -- okay. And just perhaps one more question on that. If the AMI proposal is approved, will that provide Kentucky Power Company with additional data associated with customers receiving service under the NMS II tariff?

A. Oh, certainly. It'll provide all customers more data, as Mr. Blankenship and Mr. West have discussed previously.

Q. Okay. On pages 40 and 41 of your prefiled direct testimony, you discuss, among other things, an Economic Development Rider, EDR; is that correct?

A. Yes, sir.

Q. Okay. And we have supplied Commission Staff with an exhibit from the application. This is Application Section III, Volume 1, Vaughan Direct Exhibit AEV-9.

MR. SPENARD: And we would ask, if possible, if the Commission Staff could have that displayed on the screen.

MS. VINSEL: Mr. Spenard, this is Ms. Vinsel. I want to make sure that -- could you tell me again, this is an exhibit to Mr. Vaughan's direct testimony?

MR. SPENARD: Yes, it is. And it's the -- the document page -- if that's helpful, the document page from Section III, Volume 1 of the application, the document page is 296 of 359.

MS. VINSEL: Okay. Ariel, we're looking at -- oop. Thank you, Ariel. Ariel, is this -- is this Document Number 8, which would include Mr. Vaughan's direct testimony?

THE WITNESS: The very last exhibit attached to my direct testimony.

MR. SPENARD: There. Okay. Thank you.

Q. And I have just a few questions about this exhibit. Beginning at line 18 of page 40 of your direct testimony, you state, in pertinent part,

(Reading) The marginal cost of service analysis shows that the Company's sole EDR customer is covering its variable cost of service and contributing to the Company's fixed cost of service while taking service under the discounted EDR rates.

Are you -- and if you want to take a second to look at that discussion, again, it's page 40 of your direct testimony beginning at line 18, the answer beginning at line 18.

A. I'm familiar with it.

Q. Okay. And in support of your testimony, you provided Exhibit AEV-9, and it contains information that's relevant to that discussion in your direct testimony; is that correct?

A. Yeah, that's correct. This is a -- it's actually a requirement of the EDR tariff. When we come in for a base rate case, we have to show the Commission that any EDR customer incremental load is -- you know, existing discounted under the EDR tariff, that it is, from a marginal cost standpoint, actually contributing more to the fixed cost recovery.

So to say that in a more summarized manner, by adding the EDR load, we're lowering overall cost of service, and that's what this exhibit shows.

Q. Well, then in terms of your answers, and I apologize for parsing words, did you say that it's contributing more to the fixed cost, or did I misunderstand that?

A. Sorry. It should be contributing more to fixed cost recovery, recovering its variable cost, and then it is making a contribution to existing fixed costs that other customers would otherwise be paying.

Q. Okay. Thank you. And I apologize if that -- the question was a little quirky on that point.

In terms of looking at the exhibit, the marginal cost of energy is $417,131; is -- am I reading that correctly?

A. Yes. It's kilowatt hour consumption times LMP, correct.

Q. So the marginal cost of distribution in the next section is given as $29,405; is that correct?

A. That's correct. We had to do distribution work to connect the customer to the system, so that work order totaled the $267,000. Then we applied a levelized carrying cost factor to that, you know, roughly equivalent to the useful life of that equipment, coming up with an annual revenue requirement of 29,405.

Q. The incremental revenue that's listed on the next-to-last line, the customer incremental revenue amount is listed at $978,909. Do you -- do you see that?

A. Yes, sir.

Q. Okay. So then the net revenue amount, $243,476. And with regard to that amount, does that amount represent a contribution to the Company's fixed cost of service?

A. Yeah. So what's going on here is, we're totaling up all of the -- we're looking at this from a purely marginal standpoint, so basically what do we look like without this customer and what do we look like with this customer.

So by adding this load, even at a discounted rate, all other customers are better off by, you know, a little over -- roughly a quarter of a million dollars there annually because we incur $735,000 in incremental costs and we gained 978,000 in incremental revenue.

Q. In terms of that -- in terms of that portion associated with the fixed cost, is the amount of contribution to the fixed costs greater than, equal to, or lower than the contribution to the Company's fixed cost of service that the customer would

otherwise pay in absence of the EDR?

A. Could you say that one more time?

Q. In terms of the contribution to the fixed cost, is the contribution to the fixed cost greater than, equal to, or lower than the contribution to the Company's fixed cost of service that the customer would otherwise pay in the absence of the EDR?

A. Yeah. So while it is recovering, it's --

(Feedback).

A. Sorry, a little feedback.

Yeah. So it is covering its incremental fixed cost and variable costs, then making an additional fixed cost contribution. Because the EDR rates are discounted under standard tariff, this customer would have paid more over the discount period, which, you know, could be five and up to ten years, depending on the EDR contract.

The point you have to look at here, though, from the EDR standpoint is, we're using this economic development tariff to try and add more billing units to the Company's service territory to lower everyone's rates, and that's important from a Kentucky Power standpoint, from a community standpoint, from everyone's rate standpoint.

And the opposite is true when we look at our NMS customers, where you're starting with someone who is contributing at full retail rates, then they add something, the distributed generation, which reduces revenues more than it reduces the costs that you avoid. So it's a big difference between what we're looking at in a MATS and what we're looking at in EDR.

Q. Okay.

A. It's the exact opposite.

Q. And when you say "the exact opposite," is it your testimony that the EDR results in a subsidy?

A. See, that's a hard one to say, because they -- the customer -- the EDR customer is paying less than it would under standard tariff, but, but for the EDR, they may not have sited with us, so it would -- everyone would be worse off by $243,000 in this example.

MS. VINSEL: Chairman.

A. That's a hard one to decide there. You know, if it's -- and that's why the economic development efforts are what they are.

MS. VINSEL: Chairman. Chairman.

A. If the customer was just going to show up in standard tariff, that's great, and maybe they site

for some other reason, but if they are price sensitive and they need -- they need a discount to maybe get their operations going in the first year, the first couple years. You know, tools like this help attract new loads, and it's hard to call that a subsidy if it's actually making everyone else better off by them being there --

CHAIRMAN SCHMITT: Okay. Mr. Spenard --

A. -- from a financial rate standpoint.

MR. SPENARD: Yep. Yes, Mr. Chairman.

CHAIRMAN SCHMITT: Can we stop just a second? There's a -- I think, a problem hearing, and it may be based on feedback from some source --

MR. SPENARD: Yes, Mr. Chairman.

CHAIRMAN SCHMITT: -- which we don't know at present; is that correct?

MS. VINSEL: It -- I just wanted to -- this is Ms. Vinsel. Ms. Blend, there's a certain amount of feedback coming through on Mr. Vaughan's testimony that makes -- it resolves itself over time, but it makes it hard to hear parts of his responses.

MS. BLEND: Okay. Our setup today is the same that -- as it has been technologically for the entire hearing. Is it possible that there's someone

who has joined by phone who has not muted themself?

MS. VINSEL: That is quite possible. I'm going to ask that everyone who is not either counsel for Kentucky Power -- excuse me, counsel for Kentucky Power, Mr. Vaughan, or Mr. Spenard, please mute your connections, your audio.

Chairman. Why don't we try it again, Chairman?

CHAIRMAN SCHMITT: Okay. You may continue with your, either answer, Mr. Vaughan, or your question, Mr. Spenard, and let's see if maybe the problem has been resolved.

MR. SPENARD: Okay. Mr. Chairman, I believe that Mr. Vaughan had completed his answer, but in case he hadn't, I'll allow him to finish, or otherwise I'm ready to move on to the next question.

CHAIRMAN SCHMITT: Let me ask, Mr. Vaughan --

THE WITNESS: I was done.

CHAIRMAN SCHMITT: -- have you completed your answer, or do you have -- please go ahead and complete your answer if you need to.

THE WITNESS: I was done, Your Honor.

CHAIRMAN SCHMITT: Okay. Thank you.

All right. Mr. Spenard, then we're ready for your next question.

MR. SPENARD: Yes, sir.

Q. I want to talk for just a few minutes hopefully, about residential fixed charges. And again, in just very simple terms, for a residential customer, is part of the bill -- and there are a lot of billing elements that go into a residential customer's bill; is that correct? Fuel adjustments --

A. Yeah, there's a number -- yeah, there's a number of surcharges and riders and whatnot that apply to all customers' bills.

Q. What I'd like to focus on is the calculation that's going to be associated with the customer charge, fixed -- the customer charge and then the variable, which is the energy charge. Okay?

A. Certainly.

Q. All right. So the total bill for a residential customer for this portion will comprise a fixed charge amount, and it's going to be combined with a variable charge amount associated with the amount of energy used by that customer; is that correct?

A. I think we -- I don't know if it was with you or someone else, but on Friday we discussed that there's really three categories of charges. You

have a fixed basic service charge, you have energy charges, and then you have percentage of revenue riders, such as the environmental surcharge and the decommissioning rider. But yes, it's heavily weighted towards energy.

Q. Okay. For the residential class, Kentucky Power is seeking to increase both -- the increases that Kentucky Power is seeking will stand to increase both the fixed portion of the residential bill as well as the variable portion of the residential bill; is that correct?

A. Yes, sir. The two -- the two proposals in concert would maintain that roughly 90 percent of the bill would be volumetric.

Q. And among other things, your rebuttal testimony addresses fixed charges, and specifically I'm looking at pages 16 and 17 of your rebuttal testimony.

A. I am there.

Q. Okay. And in terms of the rebuttal testimony, is it true that there has been a reduction in normal (audio lost) Virginia and Kentucky, even as the fixed charge has increased?

MS. BLEND: Mr. Spenard, I don't know if it was on our end or your end, but your computer froze

and we didn't catch all of your audio. Would you mind repeating your question?

MR. SPENARD: Oh. And thank you. And anytime there's an issue, just tell me and I'll repeat the question. And I'm looking at Mr. Vaughan's rebuttal testimony. We're at pages 16 and 17 of the rebuttal.

Q. And the question is of whether it's true that there has been a reduction in normalized residential usage in (audio lost) as the fixed charge has increased?

A. You kind of froze again there. So is the question that has there been a reduction in average normal usage over the same time that the basic service charge has been increasing in West Virginia and Kentucky?

Q. Yes, Mr. Vaughan.

A. Yes, as the graph --

Q. (Indiscernible).

A. -- on page -- as the graphs on page 16, R16 and R17 show, you know, over the same period of time, the basic service charge has been increasing on residential customers' bills. The average residential customer usage has been declining.

Q. Okay. Does American Electric Power have

operations in Virginia?

A. Yes, sir.

Q. Okay. And this will be -- and we'll reduce it to writing as necessary, but as a post-hearing data request, KYSEIA would like for Kentucky Power to provide an illustration for Virginia Power, similar, the same format, same time period as the figures AEV-R1 and AEV-R2 appearing on pages 16 and 17 of the rebuttal testimony.

A. Well, we can certainly do that, but I can -- I can maybe help short circuit that a bit. The customer charge, the basic service charge there has been the same for over a decade, and you see the exact same usage pattern, so it kind of makes my point that customers are not, you know, using more or less energy based on the basic service charge level, they're using based on their lifestyle and weather patterns. And when you take weather out of it, you get this normal average -- you're getting a lessening of average residential load over time.

Q. Okay. And I appreciate the comprehensive response, and that will certainly help, but with the data request, we're going to ask, but do appreciate the explanation.

In terms of --

A. I just wanted to let you know that it's a straight line. There's been no increase in the service charge in that jurisdiction.

Q. Okay. Well, that's helpful, and I appreciate the information.

In terms of energy efficiency reductions that you identify in your rebuttal testimony, if you know, is any of the change attributable to progressively increasing appliance energy efficiency standards?

A. Well, I think it's -- you know, when I talked with our team that monitors load and for forecasting and just general economic purposes, that's a lot of what they say is what -- what we would call latent EE, where it's household appliances and other things that you use in your normal life just becoming more energy efficient over time, such as, you know, people going from the incandescent light bulb in general to maybe CFLs, and then now maybe LEDs, you know, there's a reduction in energy usage, you know, based on those common technologies.

Q. In addition to common technologies, are building codes having any impact on the energy efficiency reductions?

A. They could.

Q. Okay. Do you recall discussing caulking in your rebuttal testimony?
A. I did. I think it's on R16. I'm sorry, R18.
Q. Okay. For caulking, in your opinion, do you consider caulking a significant long-term investment in energy efficiency?
A. Well, I don't know if you've ever gotten that stuff somewhere it shouldn't be, but it tends to stay forever. So I'm not sure about how -- a term I would quantify it as, but the example where I use caulking, because it's a common weatherization, energy efficiency measure, is just to provide that simple payback example. And the same -- the same simple payback math works out for more substantial, longer, whatever term, investments you're making in energy efficiency. The math's the same.
Q. Well, in terms of an example of that longer term -- that longer term effort, would a more efficient HVAC unit be an example of one of those longer-term steps for energy efficiency?
A. Certainly. And it would have a much higher up-front cost, and so generally a longer payback, but the difference in payback is the same. It's -- this example is done in a vacuum, and the Company's proposal in terms of the basic service charge does

not affect the binary decision of whether you do or don't do an energy efficiency measure.

Q. Does AEP study the price elasticity of demand among its customers?

A. I do not, and what I have generally observed is they are more -- they're more correlated to weather than they are price, especially in our Appalachian jurisdictions that have a high electric heat penetration, and then again, air-conditioning in the summer.

Q. With regard to electric heating customers, you mention electric heating in your rebuttal testimony, pages 19 and 20; is that correct?

A. I do.

Q. Okay. When are Kentucky Power Company's winter peaks?

A. When customers are using their electric heating. And the distinction is that that's a distribution peak versus a cost-causing generation or transmission peak. So, yeah, it's factored into the distribution cost of service, right? We have to -- Mr. Phillips builds his distribution grid to handle that peak electric heating load that's between 6:00 a.m. and 8:00 a.m. on a, you know, January or February morning where it's very cold and

dark and customers are waking up and heating their homes before they start their day, right? Versus, you know, as we discussed earlier, you have generation cost-causing peaks in the summertime, which electric heat -- you know, PJM's July -- June, July, August, September, five highest peaks, which occur in the afternoon because of air-conditioning load, so obviously electric heating is not contributing to those.

Q. What percentage of the Company's residential customers use electric heating?

A. It's over 50 percent. I think the exact number is in one of my many pages of testimony somewhere, if not in a discovery response, but it's -- I want to say 61 percent. I know it's over 50.

Q. Okay. Hypothetically, if Kentucky Power had no electric heating customers, what impact would this have on peak loads for the winter peaks?

A. I don't think I can answer your hypothetical.

Q. Well, I'll take one step back, perhaps. If Kentucky Power had no electric heating customers, would that have an impact on the peak loads for the winter peaks?

A. So you're saying if we didn't have a load,

would it -- would the peak be less?

Q. If you didn't have electric heating customers, would that have an impact on the peak loads for the winter peaks? Not trying to quantify what the effect would be but whether or not there would be an effect.

A. Well, again, hypothetically, yes, if they're -- if no one was heating in the wintertime, all other things being equal, loads would be less in the wintertime. And again, that wouldn't affect the, you know, generation or transmission costs, but it would -- it would theoretically -- and again, in your hypothetical here, it would change how Mr. Phillips designed the distribution system to serve those customers.

Q. So with regard to the change in design under the hypothetical, would that cause a lower or a higher or no impact to the allocation of cost to the residential class?

A. Again, you gotta differentiate between causing of costs and allocating costs. Let's -- again, purely hypothetical, we could use smaller -- I don't even know if this is true, if smaller transformers cost less, but theoretically for this hypothetical, because we have no electric heat all

of a sudden, Mr. Phillips used smaller, less expensive primary and secondary distribution transformers to design some distribution radials, so you there would have a reduction in overall cost of service, again the revenue requirement. Our plant service would go down. The return noncomponent of that would be less -- depreciation expense is less.

So the total pie which you need to split up is smaller. However, you can't really say how that affects the allocation of that cost, because other customer classes use distribution equipment as well, and it's all -- cost allocation is your peak relative to everyone else's peak relative to the peak you're measuring. So you can't definitively say whether it is less cost to the residential class or not. Under your -- the hypothetical, there's less cost overall because, again, I made up something that those transformers cost less now.

Q. With regard to the shifts that would take place with regard -- with regard to what happens when customers shift their loads away from peak hours, and I apologize because you've -- we've asked this question a little differently previously, but with regard to what takes place when customers shift their loads away from peak hours, does that impact

the cost-of-service study?

A. So again, if it's a cost-causing peak and when you're saying cost of service, you're saying total cost of service, like what is the revenue requirement, yes. And that's what we've studied in this rate case and the avoided-cost rates for NMS II, it's what we've looked at in the Company's proposed DRS tariff, and it's what we looked at in the AEV Exhibit 9 on that marginal cost-of-service study for the EDR customers. So yes, there are certain peak load reductions that have value, and we've quantified those and we've included them in the applicable tariffs.

You know, back to your hypothetical, does it actually change how costs are allocated, you can't say because, you know, if you change that peak, the peak hour may change, so the same customer may get caught up in it later where their behavior is different.

You see that -- you know, again, like if we don't have electric heating load in the hypothetical, the distribution peak isn't going to be at 6:00 a.m. anymore, it's going to be some other hour, and who knows what the customer that now isn't hypothetically an electric heating customer, what

their load is at that time. You just -- you just can't say.

Q. Okay. For the NMS II tariff proposal, is the market value, as you use that phrase, is that a long-term projection of value?

A. So I don't like the term "value," because, you know, it's either cost or it's revenue when we're looking at things. Value gets too many qualitatives into it.

The test year study I did to show kind of that independent power producer view of what a DG system is worth from a revenue standpoint is a test year, test year analysis, but that -- so, I mean, it's not a long-term revenue study.

Anything -- you're looking out on commodity prices, you do anything long-term, it's very speculative, you know, because you get a lot of -- a lot of different opinions as to what commodities will be, you know, next year versus ten years down the road.

Q. Well, with regard to cost and revenues associated with these projections, does the NMS II tariff proposal, does it -- does it incorporate or otherwise attempt to capture the change to ratepayers for, say, decreased utility investments

over time?

A. Yes. It absolutely does. I discussed this in my direct and my rebuttal. We've incorporated the reduction in generation capacity costs, the reduction in allocated fixed transmission infrastructure costs, the avoidance of distribution line losses, of course, energy transmission losses that go with the marginal cost of energy. That's all been incorporated.

Q. For planning purposes, does Kentucky Power Company base its investments on the short-term market cost of capacity, or does it consider long-term costs for various options for meeting its load requirements?

A. Yeah. So if you're looking at whether you're going to add the next increment of capacity or not, that's an IRP-type study, and, yeah, you evaluate the entirety of the investment horizon that you're looking at to find the theoretical least-cost option for all customers.

And that's distinctly different from what's going on in NMS II, because you have -- you have something that's come onto the grid and it's caused a load reduction, and the value of that is what it is. The Company is capacity sufficient, and thus --

therefore, the incremental value is either zero or it's the value of what the next sale of link we can make is. And the same is true in the Company's DRS proposal, where we're valuing the -- what an increment of load reduction is worth, and what you would pay someone to interrupt their load. So it's completely consistent.

Q. If Kentucky Power Company invests in utility-scale solar, would the Company earn money based only on its PJM costs, sale of capacity in PJM, or would it earn based upon its fixed investment cost of the resource?

A. Yeah. Again, we're -- the Company is a regulated utility. A customer putting DG on his house is not a regulated utility. So, yes, we -- the construct here is we make an investment, as approved by the Commission, and in terms of that -- and when we do that, we earn a return on our investment, return on our investment, and we pass through our costs of operating said investment, the generation facility like utility-scale solar. You know, and part of the evaluation of whether you make that investment or not is you're going to stack it up against other supply-side and demand-side resources to see if it is the least-cost investment.

And yeah, I can -- I can tell you it would not come in at ten cents a kilowatt hour like what we're paying customers during the test year for DG net metering. That would not be the least cost of our options.

Q. Well, if energy prices were to fall, would Kentucky Power's return on investment in utility-scale solar, would that return also fall?

A. The Company's investment would not change because of commodity prices, because there's no -- or there's no fuel component to solar. But the thing to remember there is that customers' bills also fall during that period because the overall supply of energy became cheaper. The construct is cost of providing service plus a reasonable return.

Q. With regard to Kentucky Power Company's capacity, is it sufficient throughout the time frame of its current integrated resource plan?

A. I am not in the IRP case, luckily, but no. I mean, I think you're looking out 30 years and, you know, after the Rockport unit goes away, Rockport Unit Power Agreement goes away in December of 2022, I think there is a deficiency, and that's part of what they're discussing in that docket.

Q. Well, and you've stated you're not in the IRP

case, and so if this isn't a question that you can answer, then that's fine, but I'll go ahead and ask it just to see if you do have the knowledge. Does Kentucky Power's plan for its preferred plan and its most recent integrated resource plan consider future carbon costs, if you know?

A. Don't know.

Q. Okay. In your opinion -- if you have one, in your opinion -- well, let me ask this question: Are you aware of AEP's vision or strategy with regard to future carbon costs?

A. I don't (indiscernible) in terms of carbon cost, but I'm aware of what Mr. --

(Feedback).

CHAIRMAN SCHMITT: I don't know.

A. -- Mr. Mattison discussed earlier this week, or I guess last week, about the aspirational goals of the Company, AEP in general. And I did address carbon costs in my rebuttal testimony, in as when there is a carbon cost -- and the Company doesn't currently have a financial cost of carbon, but when there is one, whether it's through some sort of a load-based cost or tax or is included in the PJM LMP through a carbon adder, that, you know, it's my proposed -- you know, I think it would be consistent

that the extended effects load or LMP prices, that NMS II customers would receive that. But to include that in the actual avoided-cost calculation before anything exists I think is a bit premature.

Q. If customer-sited solar grows less under the NMS II proposal, will Kentucky Power's cost for carbon emissions increase?

A. Can you repeat that? I didn't get the first part.

Q. Okay. I'm sorry. If customer-sited solar grows less under the NMS II proposal, if it's approved, will Kentucky Power's cost for carbon emissions increase?

A. Well, you can't really say because you don't know what the basis for carbon costs are going forward. I mean, an example of that would be, look across the state line into Virginia, where Virginia's joining the Regional Greenhouse Gas Initiative, or RGGI, and they are going to pay -- Appalachian Power is going to pay a cost based on its Clinch River gas plant source. So you're going to pay a carbon cost there. It doesn't matter what the load is. So it's source based.

So you can't really say, whatever happens with DG solar, it goes up, it goes down, if it has

any sort of impact on any actual out-of-pocket carbon costs, because you don't know what the construct is. We don't have a construct of what's in Kentucky now.

Q. And I'm not -- I'm not asking for a legal opinion on this; I'm asking for your understanding as an expert in utility ratemaking.

In your view, does the Kentucky Public Service Commission have the ability to adopt a reasonably common approach for net metering the same as it does for many other facets of ratemaking?

A. My nonlegal, simple-ratemaking-guy opinion is that the Commission has the ability to -- you know, within the scope of the underlying statute, to apply that statute. They're delegated authority to do so in balancing the interests of customers and the Company and all included parties. So, you know, they can -- they can do what they're within their rights to do.

Q. Okay. For Kentucky Power Company, does it allocate its primary distribution costs based upon 12CP?

A. Yes.

Q. Okay. So summer contributions to peak load contribute to lower cost allocation to the

customer's respective class; is that correct?

A. Not necessarily. You know, as we've discussed several times, you can't look at just one thing in isolation in a class cost-of-service study, right? Because you have -- you have a number. Again, in this case it's 70 million that's getting allocated, and some of that could be allocated away for a peak reduction of one class and allocated right back to that class from peak reduction in a neighboring class.

So when you're talking primary distribution costs, those are only being allocated amongst the commercial and residential classes. And so to the extent you have -- and I assume we're talking about net metering here, so to the extent you have a customer system reducing a peak in the summer 12CP primary distribution peak in general service and residential, you just push the two costs back and forth and they don't go anywhere. It's the same pie, it's just how you split it. There's no reduction.

Q. Okay. And if you know, does the NMS II proposal contain any price signal that would incentivize the use of battery storage to mitigate morning peaks in the residential class?

A. Yeah, I think I discussed that in my rebuttal testimony that -- you know, in response to Mr. Owens saying that it is a -- NMS II's incentivizing people to move their load on peak, and NMS II is not providing a price signal by -- it's potentially providing a price signal for customers to more closely match their customer-generation profile with their load profile. One way to do that would be through energy storage.

Q. And then I'm going to ask you some questions regarding the Kentucky Power Company's residential time-of-use tariffs. And hopefully we can do this without -- hopefully we can do this without asking them to be pulled up. But in terms of the schedule RS-TOD, will you accept, subject to check, that it has an on-peak period of 7:00 a.m. until 9:00 p.m. on weekdays? Does that sound correct?

A. That's correct, yeah.

Q. Okay. And the daytime netting period proposed under NMS II is from 8:00 a.m. to 6:00 p.m. on weekdays; is that correct?

A. Yeah, that's correct.

Q. So with regard to the daytime netting period, it's entirely within the peak period on weekdays; is that -- is that correct?

A. Can you say that again?
Q. With regard to the daytime netting period under NMS II, that period falls entirely within the -- entirely within the on-peak period under RS-TOD; is that correct?
A. Yes, it -- yes, it does. But two things we're trying to accomplish, two different -- two different ends, right? The RS-TOD is a noncost-based, just price signal trying to -- you know, again, peak power is not -- is not worth -- it does not cost what that on-peak rate is there. It is trying to artificially incent customers to reduce peak usage and shift some of their habits to off-peak and weekend times, whereas NMS II is trying to get net metering service closer to its cost of service there and properly value the avoided cost of net excess generation.

So, yes, we -- the peak periods are different because the sun doesn't shine at 9:00 p.m. at night, generally, or 7:00 a.m. on January mornings. So it's trying to match up solar generation and customers' residential load.
Q. Okay. So with regard to a second schedule, RS-TOD 2, you agree, subject to check, there's a period on the schedule from November 1st to

March 31st where the on-peak period is from 7:00 a.m. until 10:00 a.m., and also there's an on-peak period from 6:00 p.m. to 10:00 p.m. from November 1st to March 31st? Does that sound correct?

A. Yes. It's looking at basically the -- if you've ever looked at a residential winter load shape, there's a bump up, a ramp in the morning when customers are, again, preparing for their day, and then usually -- you know, they stop heating as much when they go to work, and then in the afternoons it ramps back up as customers come home. So, yes, there's -- it's just that rate schedule is just another take on RS-TOD that we put in a number of years ago. I don't know, probably ten or so.

Q. And in terms of that summer period that's appearing on the RS-TOD 2, from May 15th to September 15th, the on-peak period is noon until 6:00 p.m. Do you agree to that, subject to check?

A. Yeah. Sounds familiar. Again, the RS-TOD tariffs have nothing to do with the netting period that we are proposing in NMS II. Apples --

Q. Well --

A. -- to oranges.

Q. Sure. But let's just talk about apples for

just a second, is that the summer peak period, noon to 6:00 p.m., that reflects a time that's different from the on-peak period from November 1st to March 31st, of the 7:00 a.m. until 11:00 a.m. and then 6:00 p.m. to 10:00 p.m.; is that -- they're different time periods for the on-peak usage for these two different periods; is that correct?

A. That's correct, because we're trying to, in RS-TOD 2 there, that summer period more closely aligns with PJM's 5CPs, those generation cost-causing peaks, so that that's what it's aligned with.

Q. Okay. For these peak periods, with regard to the RS-TOD and RS-TOD 2, are these peak periods -- are the time frames when the peak loads on different levels of the system might occur, even though a seasonal peak or a monthly peak is a single-hour issue?

A. Yes. You're trying to capture a -- right, a single monthly hour in some sort of a period of time, and that's what -- why those tariffs are the way they are.

Q. Okay. And with regard to how the NMS II tariff will operate -- and I'm going to use a hypothetical, and this is for simplicity. If,

during a billing month, a customer produced 200 kilowatt hours of exports during the daytime period and only used 100 kilowatts of that -- of that available-for-export amount, the customer would have 100 kilowatt hours of daytime use left over or in the bank, so to speak, for netting periods; is that correct?

A. Your terminology is a little confusing there. I'm going to assume all of those figures were kilowatt hours, and I think you threw one "kilowatt" in there, which is an instantaneous figure versus a volumetric figure, and then if it -- that example is over a month, there's no bank, it's you netted out those 100 kilowatt hours of load, then the customer was paid at the avoided-cost rate for the excess 100 kilowatt hours of that negative energy.

Q. Well, and you're a very careful listener, and I -- and I believe it's probably the case that I did use quirky terminology, and I apologize for that, but I want to go back and cover something else again. In terms of the netting period, is that if you have a customer who has reduction in excess of their usage during a net -- during a netting period, that -- on a single day I produce more than what I use, as long as it's within the netting period, the

next day, if I use that amount of generation -- if I use an amount of generation in excess of what I produce, I do have -- do I have the ability to take the prior day's excess during the netting period and have that -- that's a really quirky question. Let me try to back -- take one step back and ask that again.

During the netting period I'm going to have generation available for my own use, and what I don't use I have available for export, is that correct, in a very simple hypothetical?

A. Yeah. Yes, sir. Within the billing period, the kilowatt hours net within the netting period, so if one day you have excess and the next day you're negative, those two things net, but it's with -- it's within the netting period for the whole month. And then the net, whether it's net load or net negative energy or exports, that's accumulated within each netting period for the entire billing period.

Q. Thank you. Thank you. With regard to the -- with regard to NMS II and what I'll refer to as the compensation rate, the proposed -- and I'm going to use an approximate amount. The proposed compensation rate for excess that's exported is

approximately four cents; is that correct?

A. Yeah, it's -- the avoided-cost rate as amended in my rebuttal testimony is between three and a half and four cents a kilowatt hour.

Q. Okay. And you have two netting periods during the day? During the 24-hour period, you have two different periods?

A. Yeah. Yes, sir. The day -- the day is divided up in two netting periods.

Q. Okay. So as a customer who shifts load from the -- as a customer who shifts load from the nondaytime period into the daytime period, is that -- the customer would also -- could the customer also shift the load associated with -- basically, let me take that question again. I apologize. Let me ask that question again a little differently.

With two periods during the 24-hour cycle, with two periods, the customer has the ability to shift load from the nondaytime period into the daytime period; is that correct?

For example, if I wanted to run my air conditioner at -- begin running my air conditioner at 3:00 p.m. in the afternoon to cool my house, as opposed to waiting until 7:00 p.m. in the afternoon

to cool my house, the customer has that ability; is that correct?

A. To the extent that there is discretionary load that a customer can move around, yes, someone could do that, but there's no underlying price signal to do that. The rate that applies to the load is the same. It's just a matter of whether -- you know, regardless of what netting period you're in, it's just a matter of how we're dealing with the compensation for the customer generator's output, whether it's actually netting kilowatt hour or it's been compensated at the avoided-cost rate.

Q. So the customer -- as a general rule, the customer's incentive is to use the additional on-peak power in the way that's going to generate the most -- generate -- the way that's going to result in the most financial benefits to that customer; is that correct?

A. Yeah, I think you're looking at it backwards. The customer's incentive is to match the generation with its load, so if a customer isn't home -- you gave the pre-cooling example, but you can't really change how your sump pump runs or how your air conditioner cools or if you have any lighting that's going to happen during the day or whatever your HVAC

is pulling during the day. Those things, they are what they are, and like I said, there's no -- there's no underlying price signal from the rates that apply to the load to make them want to shift.

Q. With regard to a customer, can a customer utilize a programmable thermostat for the HVAC system, if they had one?

A. Yeah, they sure can. I mean, you -- a lot of customers, as you see in load profiles, they generally keep the -- keep the home -- if they're leaving for work in the morning, back when we used to do things like that, you know, you would keep it at a different temperature than when you were actually at home. You know, so programmable thermostats, absolutely.

But there's no price signal, no reason that a customer would want to just, you know, for no reason, cool their home more while they're not there. You know, you still want to use the same amount of energy overall, and the rate that applies to that load, if it's net billing, is the same no matter when it occurs.

Q. Well, but for NMS II customers, they're going to have -- the 24-hour cycle comprises two periods, basically, you have the daytime period and the

nondaytime period; is that correct?

A. That's correct.

Q. Okay. And then with regard to the customer's usage patterns, there is a distinction between -- because there's a difference in the netting period, there is a distinction between when the customers use their energy? It can have a different consequence depending on the time of day that that customer receiving service under NMS II uses their energy?

A. Yeah, my point is that there's no difference in the rate that applies to net load, whether it's in netting period one or netting period two. You have net billing load, it is -- net billing kilowatt hours or units or kW, it's billed at the same standard rate.

And again, there's no -- if a customer was going to use 1,000 kilowatt hours in a month or 1,240, the average in the case here, there's no price signal that would say I am better off using 1,350 now, you know, to cool my home while I'm not there, just to take advantage of the netting, because you'd still be better off having that net energy credited to you at the avoided-cost rate than using extra energy.

And then if it's simply shifting some load from one period into another and you're aligning that with your behind-the-meter generation, you know, the Company is not going to see any additional cost from that because you're netting it at the meter. So there's no net load there.

Q. I just have -- one second to look at my notes.

MR. SPENARD: Mr. Vaughan, thank you for -- thank you for your patience and thank you for your answers.

And, Mr. Chairman, with that, KYSEIA is finished with its examination of Mr. Vaughan.

THE WITNESS: Thank you.

CHAIRMAN SCHMITT: Mr. FitzGerald, I assume you have cross-examination?

MR. FITZGERALD: I do. I do, Your Honor, and I didn't know whether you wanted to go ahead and take a break. It's 10 --

CHAIRMAN SCHMITT: That's why -- usually we would want to take one at 10:30, but since we don't want to interrupt your cross, let's take a break or go into recess now until 20 minutes until 11:00 -- hold on. Ms. Vinsel?

MS. VINSEL: Vice Chair Chandler had asked

that we take a 20- to 25-minute morning break.

CHAIRMAN SCHMITT: Okay. Well, that would put us --

MS. VINSEL: Would you like me --

CHAIRMAN SCHMITT: -- 15 till. I understand, basically, the Vice Chairman would like to take a longer break, so let's take a break, 20 to 25 minutes, until 10 minutes until 11:00 o'clock, and we'll come back then and you can begin your cross-examination, Mr. FitzGerald.

MR. FITZGERALD: Thank you, Mr. Chairman.

CHAIRMAN SCHMITT: Thank you.

MS. BLEND: Thank you.

(Recess from 10:27 to 10:53 a.m.)

CHAIRMAN SCHMITT: Okay. I think we're now back on the record. Is the witness and counsel for all of the parties present?

Well, Mr. Vaughan, even you have to eat. I understand. If you're prepared, if you're ready to go, Mr. Vaughan, Mr. FitzGerald, you may commence your cross-examination.

Mr. FitzGerald, we cannot hear you. You must be on mute.

Can anyone hear Mr. Fitz -- you can? Well --

MS. VINSEL: We can't -- we couldn't hear

Mr. Vaughan.

CHAIRMAN SCHMITT: We can't hear either Mr. Vaughan or Mr. FitzGerald, so we're going to have to take a minute.

VICE CHAIRMAN CHANDLER: Can you hear me, Mr. Chairman?

CHAIRMAN SCHMITT: I'm sorry?

VICE CHAIRMAN CHANDLER: Can you hear me?

CHAIRMAN SCHMITT: Yes. Can you hear Mr. Vaughan and Mr. FitzGerald?

VICE CHAIRMAN CHANDLER: I can. Maybe we can give it another try. Mr. FitzGerald.

MR. FITZGERALD: Okay. Absolutely. Your Honor, can you hear me now?

CHAIRMAN SCHMITT: Yes.

MR. FITZGERALD: All right.

CHAIRMAN SCHMITT: Mr. Vaughan, would you speak up?

THE WITNESS: Yes, sir.

CHAIRMAN SCHMITT: Okay. So -- all right. So looks like we're okay. Now you may begin, Mr. FitzGerald.

MR. FITZGERALD: It may be more merciful, Mr. Chairman, if you can't hear me, I'm sure.

* * *

CROSS-EXAMINATION

By Mr. FitzGerald:

Q. Mr. Vaughan, I'd like to start out, if I could, by following up on a few points from your -- what I think I heard you say in earlier -- in questioning, but I'd like to clarify in case I got it wrong. Okay?

Following up on your point regarding the reduction in bills during the recent years, am I right that part of that reduction is due to tax reform and that the tax reform reduction ends at the end of 2021?

A. There's a couple different pieces to tax reform.

Q. Okay.

A. One of the larger impacts being the 35 percent marginal rate going to 21 percent, so that was incorporated into the Company's last base rate increase. So that reduction was there, and then, you know, as Mr. Kurtz and I discussed, based on the KIUC complaint, we then instituted the Tariff FTC here in Kentucky to pass that excess ADFIT protected and unprotected. So the protected piece of that will continue to go on. The unprotected, again, depending on what happens in this case, could go on

for a few years, could go on for 18 years.

Q. Okay.

A. That's a portion of it. Fuel decrease is a -- is a big chunk of the reduction in rates over time, as well as the net credit that was flowing through Tariff PPA for a little over a year.

Q. Okay. You froze there for just a second. Okay? Did you hear me okay?

A. Yes, sir.

Q. Okay. Great. Mr. Blankenship's testimony, his written testimony, concluded with a note that the anticipated cost of AMI is aided by the experience gained from other AEP companies, and then he deferred the rate issues to you. So it's like everybody has, like, laid it on your desk, so the buck stops here, or in this case 37 million bucks stop here.

So I was wondering, do you know whether other companies that have been noted as either having deployed or deploying AMI, those being Kentucky Power affiliate PSO, Ohio Power Company, Appalachian Power Company, and AEP Texas, did formal cost-benefit analyses when they were requesting approval for AMI?

A. I don't know whether or not they did

cost-benefit analyses -- well, all of them, anyways. I know APCo did not. I was just involved in the Virginia rate case there that addressed AMI. It was very similar to Kentucky Power's request in that current AMR meters are obsolete, past their useful life, so AMI meters are going in --

Q. Okay.

A. -- to those customers. Three of those companies you mentioned do recover AMI through a rider, though, similar to what the Company is requesting here.

Q. Okay. And how many of the other ones are recovering costs through part of rate base? Or base rate. I'm sorry.

A. Of the AMI companies, I believe APCo.

Q. Okay. You responded to a question from Mr. Spenard that the NMS II customer is being, quote, unquote, paid for excess generation. You do understand that the customer in Kentucky receives a credit rather than a payment and that that credit is not redeemable except against usage?

A. However it's characterized, it is -- it is compensation or a credit on the bill, and, you know, the Net Metering Act states that -- prevailing law states that net metering is the financial netting of

the cost of their load and the price paid for the excess generation.

Q. Well, I'm not going to ask you to characterize the law, it speaks for itself, but you do understand that the credit is not able to be cashed out, that it is simply a credit against future use -- future usage, and when the customer ceases to be a customer, that credit stays with the Company and not with the customer?

A. I'm not aware of what happens at the end of the -- end of a net metering contract, I guess, but, you know, right now it would be cashed out every month under NMS II per the law --

Q. Well --

A. -- in the form of a bill credit.

Q. -- again -- yeah, in the form of a bill credit. Okay. Thank you. So it is not cashed out at all, it is credited against usage; is that correct?

A. I think we're splitting hairs here. The customer is receiving compensation at some level on its bill.

Q. With all respect, Mr. Vaughan, we are certainly not splitting hairs, and I won't go into the distinctions between an independent generator

under PURPA and the tax consequences versus a credit that is dollar denominated but is not a cash payment. We'll just leave it at that.

As you understand it, does prevailing law, that being Kentucky law, require KPC to propose limiting the credit, or the use of those credits to peak hours?

A. Are you referring to the bill credits we were just discussing?

Q. Yes.

A. No, I don't think there's anything in the law that limits that, but the Company's proposal limits that because the law does. It allows the Company to recover its cost of service to serve those net metering customers that use the Company's system every day.

Q. Okay. Thank you. And finally, you indicate -- you seem to indicate -- and I was a little concerned about this. You seemed to indicate that the prevailing law required you to propose the avoided cost as the compensatory credit rather than some other value. Is that your testimony?

A. Are you referring to how we have -- we have characterized the avoided cost, how we have calculated it?

Q. I was referring to the fact that in response to Mr. Spenard's questioning, you said there were two reasons why you went to the avoided cost, and one of them was because the law required it. Did I misunderstand you?

A. I don't think I said that, but --

Q. Okay.

A. But basically the Company is valuing an avoided-cost rate based on what the actual avoided costs are, so that when a customer's load is reduced through net metering or excess net metering in that interval, what is the total cost of service actually realizing? And that is what is in that avoided-cost rate.

Q. Okay. So again, the law did not require you to go with the avoided-cost rate, that was a decision of the Company?

A. Yeah, you're absolutely correct. And, you know, as Witness -- KIUC AG Witness Baron stated, we could have also proposed a straight buy/sell type tariff and done it as LMP as other companies do, or pick your cost base method. But, yes, I do believe it needs to be cost based. But, no, we could have done it another way.

Q. Okay. We're going to shift gears a little

bit. How -- do you know how the costs of the current generation of AMR meters were recovered from customers in the Kentucky Power service area?

A. It's part of the Company's base rates.

Q. Okay. And are those meters fully paid off, or are the residential and commercial ratepayers still paying for them?

A. By "paid off," do you mean are they fully depreciated?

Q. Yeah.

A. It my understanding they are not fully depreciated as the Company has not updated depreciation rates in quite some time.

Q. Okay. So do you know how much customers are paying a month for the -- for that generation of meters?

A. I do not know specifically what the AMR costs per month per customer is, no.

Q. Okay. And under the proposed grid modernization rider -- can we say GMR?

A. That would be great.

Q. Thank you. That would be used to pay for the cost of this initiative. What will the customers pay each year until the recovery of costs and the return on investment are recovered? Do you recall

that offhand?

A. I will actually point you to Exhibit AEV-8 --

Q. Okay.

A. -- in my direct testimony.

Q. Okay. AEV-8?

A. 8, yes.

Q. Great. Thank you.

A. It shows -- yeah, it shows in there, during the four-year deployment and then out -- I think I did this for ten years -- what the annual revenue requirement is based on the current cost estimates and associated operating expenses.

So in that first year, it's the 1.1 million, and just because we were implementing rates based on that, if you go over to my -- it would be the third page of that schedule, you can see that a residential customer is going to pay 31 cents per month in -- for a GMR rate associated with AMI.

Q. Okay. And that's year one, or is that -- is that every year?

A. That is year one. So obviously, that would grow over time as the -- as the revenue requirement, as you can see on page 1 of AEV-8, grows over time as you deploy the meters.

Q. Okay. Thanks. And did you consider -- or

did you compare the cost recovery if you had done it through base rates rather than a rider?

A. I mean, the -- so the revenue requirement wouldn't change.

Q. Right.

A. It's the same whether you put it through the rider or whether you put it in base rates. It's just a matter of, you know, the flexibility of recovery and, you know, as we've said a few times, trying to balance all the -- all of the moving pieces in this rate case, you know, customer bill impacts, the Company's financial situation, you know, that's why it went into the GMR rather than base rates.

Q. Okay. I understand the Company needs the money, okay, but my question was: Did you look at the comparative rate impact on ratepayers? They're paying 31 cents a month in year one for the rider. What would they have paid in year one per month if you had gone with base rate?

A. The same or more. And I say "more," because if we were doing it in base rates, we would probably try and propose some level of year two costs in that as well as you forecast out, since it's not flexible at all. And as you see, the current plan is to ramp

up that spend over time as you do the installations. So, you know, if you put it in base rates and you freeze it at that year-one revenue, it would be baked into the Company's base rates, it may change operationally how Mr. Blankenship and Mr. Phillips actually execute this.

Q. Do you know whether KPC considered a pilot program to test the assumption that net -- that AMR would be of interest or benefit to the customers?

A. I have no knowledge of a -- of a pilot program. And again, the reason -- my understanding behind that, is that, you know, we're looking at this from an obsolescence standpoint.

Q. Right. Okay. So does Kentucky Power -- do you know whether they currently report energy usage by the customer on a monthly residential bill separate from the meter charge?

A. Does the bill have monthly kilowatt hour usage on it?

Q. Does it separate out what you're paid -- what you're being billed for energy as opposed to your meter charge?

A. I'm not certain what the current bill format looks like. It may just have total charges. It may have total rate billings, then taxes. I'm not a

hundred percent certain.

Q. That's a fair answer. Okay. If we could shift again to time-of-day rates. This is the voluntary buy-in -- or voluntary tariff that you have for time of day. Is --

A. Existing TOD rates?

Q. Yes, that TOD 2, is that -- is that it?

A. Well, no, we have a number of time-of-day rates, and have for quite some time, residential, commercial.

Q. I'm sorry. This is the, quote, experimental residential service time-of-day tariff.

A. It's been experimental for a long time now, I think, yes.

Q. Got that. Got that. We've got a pilot going on in Columbia Gas that has been flying around for a long time.

Is Kentucky Power's cost of service, cost of power the same at all times of the day in all seasons?

A. Can you repeat your question?

Q. Yeah. Let me just -- the average customer gets a kilowatt hour charge, right, a levelized charge, but the actual cost of either producing or acquiring electricity for sale changes over time,

does it not?

A. It does, and rates do as well. When we look at base rates here, they're fixed. Those are those basic rates, right? They don't have the energy -- they don't account for what I would say the more volatile costs are. Like we talk about energy supply, that is true of every month, so that customers do see -- you know, can see widely varying rates through the -- through the FAC and other power supply costs.

Q. Okay. And are Kentucky Power's costs of generating or acquiring electricity higher during peak demand?

A. It totally depends. Ten years ago, when I was in more of the commercial business here, I would say yes. Now, anybody's guess. I mean, it's highly dependent upon, you know, market forces beyond just what Kentucky Power is doing.

And again, you know, our peak time may not align with the peak time of PJM, so you may see very little fluctuation in LMPs. It just depends.

Q. Okay. How many residential customers do you know took service under the experimental time-of-day tariff, residential tariff, during the test year?

A. Very few. I don't have the exact number, but

it's in the -- it's in the test year schedules.
Q. Okay. Roughly? 100? 200?
A. So on RS-TOD 2, there are zero.
Q. Okay.
A. And on RS-TOD, we have six.
Q. Okay. Very popular program, then?
A. Very.
Q. Okay. The -- is it true that with the current net metering tariff -- we'll call that NMS I.
A. Sure.
Q. The -- a customer could now choose to be a customer generator and opt into the TOD rates?
A. I think that's true.
Q. Okay. Do you know whether they would be able -- oh, I'm sorry. Go ahead.
A. I'm not a hundred percent certain. I would need to go back over the existing tariff, but, yeah, that does -- sounds right.
Q. Okay. Would they be able to under the proposed NMS II?
A. No, they can't, because of the overlying netting periods.
Q. Is the current voluntary TOD tariff available to customers using the AMR meter technology, or do

you have to install a new meter to enable them to use the TOD rates?

A. The way I understand it is it's an AMR meter, but there's essentially another piece of equipment that gets plugged into it. There's a lot of -- a lot of metering charges that I don't understand, but there's other registers or something that happens within that AMR meter to provide the billing, we'll call them the buckets or netting period -- not netting period. The period -- the billing period, right? Because we have to accumulate usage by period, then send it to our billing system to be able to bill that tariff, but it's an AMR --

Q. Okay. As --

A. -- meter.

Q. As I understand it, now, and I could be wrong, the AMR meter is capable of producing that information whether somebody is using energy or electricity at peak times, as defined by the Company, or off-peak times.

A. Yes, that's how we bill the on-peak and off-peak rates in the tariff.

Q. Okay. And then does the customer under that tariff get some information saying here are the hours that are peak, here are the hours that are off

peak, so they know and can adjust their usage?
A. Yeah, it's in the tariff.
Q. Okay.
A. So it's stated in the tariff they signed up for.
Q. Wonderful. And why would a person choose to participate in a TOD rate program, do you know?
A. I do not know what those six customers are thinking, but generally it would be if you have some sort of -- some sort of portion of your load that is -- that I would characterize as discretionary and easy for you to move from time period to time period, such as, you know, an electric vehicle, like, again, back to my EV tariff, it would be, you know, some sort of discretionary load that you want to -- you have the ability to move off of one higher-priced-type time period to a lower price time period, take some sort of financial advantage of that.
Q. Excellent. And does the Company benefit from the customers doing this TOD program?
A. Yeah. It's the same discussion as I had with Mr. Spenard there on the -- you know, if we can reduce load at certain cost-causing peaks, you know, the overall cost of service benefits, and that's

what we have priced in NMS II and my other -- my peak-shaving tariff, which I just lost my -- DRS --

Q. Yeah.

A. -- the DRS tariff.

Q. Okay.

A. Same concept.

Q. Believe me, Mr. Vaughan, I have lots of those moments, so -- and so as -- and just so I understand, the benefits that somebody participating in the TOD, although, you know, when there's six of them within the entire system, we can assume they're fairly marginal benefits, but those benefits to the system are baked into the prices, right?

A. That's right. It's baked into the effective rate they get, you know, which is lower off peak when they move. You know, let's say, for example, their standard bill would have been ten cents and now it's seven cents because they shifted some portion of the load off peak, and there's some sort of roughly commensurate reduction in the overall cost of service. Cost of service went down, customer's bill went down, same as any sort of peak-shaving paradigm.

Q. Got it. Got it. And do those participating customers, assuming that they do have some

discretionary load that they can shift to a lower peak, are they paying -- when they do shift that load, are they paying as much of the fixed costs that are embedded in the volumetric rates as they would if they used all that energy on peak?

A. It depends. When we design these TOD rates, you design it so that the distribution costs are the same in every component, because obviously, distribution infrastructure doesn't move, doesn't matter when you use -- when you use it, whether it's on peak, off peak, or how much you use it, it has to be there for you to receive service. So those rates are constant across all the TOD period, the prices.

And then you basically look at -- largely, transmission is the same way, so the wires charges, and then you kind of create that noncost-based price differential on the generation portion of the bill.

Q. Okay. Okay. And the -- getting -- now, this -- I think you've almost answered this question too. Regarding the rates, what is the -- if you could -- and if this is not something that you've got in front of you, just say so. But can you break down for me the components of the rate for on-peak consumption, which I understand to be 15.7 cents per kilowatt hour, as opposed to the off peak of 8.25

cents per kilowatt hour? What's the -- what's the differential there, if you're -- if you're -- if you're building in the distribution costs, you're building in the transmission costs as being fairly fixed, what floats between those two rates?

A. Well, like I mentioned, the differential isn't cost based. There also would be almost no differential because there's very little difference now in on-peak and off-peak prices. As I discuss in my testimony, it's purely an incentive price signal to move folks off. If it was cost based, it would look exactly like the price signal in NMS II or DRS.

Q. Okay. Okay. Thank you. Moving on. Do, do, do.

Do you -- do customer-sited -- or let's say rooftop energy, solar energy systems normally generate energy during the RS-TOD on-peak periods, which I think is 7:00 to 9:00 Monday to Friday?

A. Yes, during the day.

Q. Okay.

A. When the sun is out.

Q. Cool. And then do they normally generate energy during the RS-TOD 2 on-peak periods, which are noon to 6:00 May 15th-September 15th?

A. They hit the summer one, they miss the --

they largely miss the winter peak.

Q. Okay.

A. On a large scale.

Q. In determining the compensation rate offered for excess generation from net metering customers, how does the NMS II tariff account for the higher value of energy during peak periods?

A. It's baked into the avoided energy rate and the avoided capacity and transmission cost rate. Those are actually marginal costs. And again, LMPs -- LMPs are almost flat. There's very -- very little differentiation anymore between an LMP, locational marginal price, being the Company's marginal cost of energy, across on-peak and off-peak periods. And so the avoided-cost rate in NMS is weighted towards the on-peak production on a solar facility. So they're getting that full compensation there.

Q. Full crediting?

A. Certainly. Full credit in the avoided-cost rate.

Q. Okay. There are, as I understand it, roughly 30 or 40 current net metering customers, including the residential and the commercial?

Just so you don't have to look, Mr. Vaughan,

the page 166 in Section III of the testimony in Volume 1 says, (Reading) At the end of the test year, there was 44 net metering customers.

Does that sound about right?

A. Yeah. We updated that in Staff 4-82. There's 46 installs in service, ten of which are commercial, so 36 --

Q. Okay. Right.

A. -- residential.

Q. And then the testimony, I think one of the other witnesses said there's potentially 30 more that are in the pipeline?

A. I believe so. I think there's -- I confirmed some. Roughly that number is between 23 and 30, I think, applications out there.

Q. Okay. And do you know how many RS customers have submitted applications that are not yet operational?

A. I do not.

Q. Okay. How many GS customers?

A. That -- I don't know. It's hard to see -- even if I did see those applications, our distribution generation group takes care of that. That was part of the confusion in our initial testimony and discovery answers is that you may have

a commercial customer with a residential customer's name on it, but it's for a commercial account.

Q. Gotcha. Gotcha. Is economic development and job creation important to Kentucky Power?

A. Absolutely. As, you know, Company President Mattison and as Company Witness Wiseman discussed, that economic development, jobs in the service territory and lowering rates for everyone is a big goal of Kentucky Power.

Q. Okay. How many -- do you -- have you figured out what the total financial impact of non -- on nonparticipating customers of crediting your current net metering customers at a one-to-one kilowatt, you know, generator-to-use basis, what the rate impact is on nonparticipating customers on a monthly or annual basis?

A. I mean, those numbers are all in the record here, especially when you look at -- I think my tables there at the end of my rebuttal testimony, we discussed what an NMS bill would be versus what a NMS II bill would be versus what a standard bill would be, and, you know, there is a subsidy there, and it's not material currently, but again, that's not one of the requirements for us to change our rates, how we treat NMS, net metering customers.

Q. When you say it's not material, did you -- do you dispute the suggestion from Mr. McDonald and that which was given by Mr. Rabago during the administrative case, which is part of the record of this case, that the impact, current impact of the one-to-one credit on nonparticipating customers is about seven cents a year?

A. I wouldn't say I agree with any of their math, especially Mr. Rabago's in that case, but it -- the subsidy is there, you're paying someone three times -- three times the cost of a good for said good, so that -- and we are availing ourselves of the Net Metering Act in this application to change our rates.

And like I say in my rebuttal testimony, there's no reason to wait until the problem is huge to fix it. I don't know if you've looked at some of those rate cases out West, in Arizona and Nevada, but they become very contentious on all sides. There's a lot -- there's a lot of money at stake there, and, you know, the Company -- the Company was prefer to fix something, send the correct price signal, and do it now, before it is a larger subsidy in rates, so that those new NMS II customers can evaluate their investment on a more reasonable

footing.

Q. Okay. So getting back to it, you didn't agree with the math, but do you have a number for what is -- what is now a negligible or a minimal impact? Have you priced out what the actual supposed subsidy is that nonparticipating customers are paying?

A. In terms of cents per kilowatt hour, yes. In terms of total dollars each year, it's irrelevant, as I've discussed.

Q. Well, if there's a subsidy that's occurring, do we know what it is in terms of what -- if I'm a nonparticipating customer, am I coughing up a penny, a fraction of a penny, five cents? It's not irrelevant to me as a nonparticipating customer if there is such a subsidy. I'm just wondering if you put a dollar value on it.

A. Just a moment.

Q. Sure.

A. Yeah. So if you look at my rebuttal page 25, customers are paying just over ten cents, 10.33 cents per kilowatt hour for a commodity they would otherwise purchase for 3.85 cents. So the difference there is what, per kilowatt hour -- it grows volumetrically as you add more to it -- what

nonparticipating customers are paying versus participating customers.

Q. Okay. And have you multiplied that cost by the -- or spread that cost among the number of customers in the residential class, and can you tell me what the annualized cost is for that nonparticipating customer because of this supposed subsidy?

A. No, because as I stated earlier, it's irrelevant.

Q. Humor me. Have you made that calculation?

A. No, sir.

Q. Okay. And why is it irrelevant? If you're so concerned that there's a subsidy occurring, that the nonparticipating customers are being asked to participate in the payment for something that -- let's assume it has no value to them. Why is it irrelevant, that -- the amount that they are being required to pay?

A. So like I said here, it's kind of a multipart answer. First off, current NMS customers are grandfathered, so they're not losing anything on their investment that they made under the old NMS tariff, right? So they made some sort of decision to put generation on their homes or their business,

and whether that was economic or otherwise, that is the deal they struck, that's grandfathered under the law.

We want to provide the right price signals for future potential NMS customers, and NMS II, so that they can make the right decision. And the Company's position is that nonparticipating customers shouldn't be funding above what they normally would have paid for electricity, that NMS II customers' economic decision, you know, their -- they can take into account if they're getting a federal tax credit or some other state program, whatever's out there, but we want to keep that out of our electric rates so that our customers aren't different.

Q. I'm going to try this one more time and then we'll just move on.

Have you quantified, on a monthly and an annual basis, what this supposed subsidy is that nonparticipating customers are paying for those that are taking --

MS. BLEND: Your Honor --

Q. -- net metering?

MS. BLEND: Your Honor, objection. This question has been asked and answered by Mr. Vaughan

several times, he's explained his answer several times, and the fact that Mr. FitzGerald doesn't like that answer doesn't entitle him to keep asking.

MR. FITZGERALD: Listen, I can dance as well as anybody. We've asked it several times, it's not been answered. There is a claim that there is a supposed subsidy, yet the Company seems incapable of determining and reporting what that supposed subsidy is.

MS. BLEND: And, Your Honor, Mr. Vaughan explained that he hasn't calculated that subsidy, and that it's not necessary to do so and he has explained why.

CHAIRMAN SCHMITT: Yeah, I sustain.

MS. BLEND: We believe --

CHAIRMAN SCHMITT: Let's move on. I think we understand.

MR. FITZGERALD: Thank you, Your Honor.

Q. Mr. Vaughan, you suggested that the time to deal with this problem is now, before it becomes a significant problem. You are familiar that there is a statutory maximum cap of one percent?

A. Yes, sir.

Q. Have you calculated what the rate impact would be on nonparticipating customers at one

percent penetration by net metering customers?
A. Yeah, I have -- I have not, but again, that 6.2 cents per kilowatt hour in subsidy, as I just discussed, the difference between 10.3 and 3.5, you know, if we change it to NMS rate where nonparticipating customers are different, there's no need to calculate it because there is no subsidy going forward, or a much-reduced subsidy.

And again, my experience in other places, every time something gets close to a statutory cap, it tends to get pushed out to a larger statutory number. We just saw that in Virginia, so -- and again --

Q. Mr. Vaughan -- go ahead.
A. -- my testimony is that we address that now so we get the right framework for customers to make their economic decisions based on.
Q. You're familiar with the fact that in Kentucky, we went from a flexible cap to a hard cap of one percent and not the other way?
A. I don't have the background on that, but --
Q. Okay. So this concern about this subsidy, these -- the indeterminate amount of this subsidy, is it higher or lower than the $3.48 a year that a nonparticipating residential customer pays to

support the TEE program? Do you know that?
A. The what program, sir?
Q. The -- is it TEE, the energy efficiency -- Targeted Energy Efficiency program? We've established that the nonparticipating residential customer in Kentucky Power service territory pays $3.48 a year to support that program.
A. Yeah.
Q. Do you know, is that higher or lower than this supposed subsidy from nonparticipating to participating net metering customers?
A. So again, the quantified subsidy is that 6.2 cents per kilowatt hour, but I do not know if it's larger or greater than the amount billed for the Company's Commission-approved energy efficiency demand response programs --
Q. Do you know whether it's higher --
A. And that's --
Q. -- oh, sorry?
A. I was just going to say that, you know, that's a program that the Commission approved, you know, in our last rate case, or something very close to it, the companion case, they eliminated the remainder of the Company's programs and that that's the one surviving program.

Q. Okay. And do you know whether it's higher or lower than the $3.60 a year that nonparticipating residents -- customers pay to support the Low Income Energy Assistance programs?

A. I don't know.

Q. Okay. And for commercial net metering customers, do you know whether the supposed subsidy is higher or lower than $12 a year that they pay to support the K-PEGG program?

A. Well, I'm -- I don't agree with your characterization of the K-PEGG being a subsidy.

Q. I appreciate that. Do you know whether it's higher or lower than the amount that is being paid by commercial customers to support that program every year at $12?

A. I don't know, and I would testify that that's irrelevant.

Q. I appreciate that too.

Do you know whether, under the three programs I mentioned, the Company gets a rate of return on the management of those programs, the Targeted Energy Efficiency, the Low Income Energy Assistance, and the K-PEGG program?

A. We definitely don't earn a rate of return on the K-PEGG program. You know, as Ms. Wiseman said,

that's a -- that's going into some of the Company's economic development efforts, which, you know, if you look at my Exhibit 9, those efforts are increasing the amount of billing units on the Company's service territory and helping to lower all customers' rates.

On the energy efficiency programs, I believe the Company receives a voided -- or, I'm sorry, lost revenues associated with the reduction in load from its energy efficiency efforts.

Q. Okay.

A. You know, which is different from what happens with, you know, net metering.

Q. Okay. What happens to the electricity, then, that the -- the excess generation that is fed into the system by a net metering customer? Is that energy resold by the utility?

A. Resold? How so, sir?

Q. Well, I -- does the -- does the electricity from a net metering customer go any further than the local grid?

A. Generally, no. I'd say it's being consumed on the distribution system, so it's netting the Company's load.

Q. Okay. And so is somebody else consuming that

electricity?

A. Between line losses and some other customer, yes.

Q. Okay. How much are the line losses?

A. Depends what customer, where they're sited on our system. As we've talked a lot here in this case, our system is very dispersed. It's not very dense. It's not -- it's most likely not going from one yard, you know, 30 feet over to the next house. That's just not how our system is built.

Q. Okay. So --

A. So the line loss could be very significant.

Q. Okay. So the part that's not lost to line loss, some other customer is consuming?

A. Yeah. As I said, it's reducing the Company's distribution level load, and that's how we've designed the avoided-cost rate.

Q. Okay. And is that other customer getting that electricity for the avoided cost, or are they paying you a higher value for it?

A. Customers are paying for service. And, again, the only piece -- there's only certain pieces that -- you're talking -- when a DG customer reduces energy, you're only talking one portion of the overall cost of service. You're talking energy

supply, you're not talking -- you know, those units are not supplying regulation, other ancillary services. They're not providing transmission service and distribution service. You know, those are all different parts of the Company's rates.

So essentially, if you do price it at the avoided-cost rate, then yes, it is exactly what that customer would have paid for those electrons had it not received them from some other DG customer.

Q. Okay. So that other customer is getting the electricity for the same price that you are compensating the net metering customer?

A. Yes, because it's only part of the bill. You can't -- I know net metering likes to wrap all of the Company's services up and provide that credit to the customer, but it doesn't change the fact that there's distribution and transmission and other infrastructure there that that customer still uses every day.

So what I'm saying is, electrons that are flowing down the system to the next customer and theoretically they're consuming them, by definition, if it's an avoided-cost rate, they are receiving those electrons at the same price as they would have otherwise.

Q. Okay. And you -- have you credited any value that having that distributed generation may have on the local grid?

A. Yes. I think I go through that -- well, let me find the part of my --

Q. No, I just -- I don't need the details. I'm just asking whether you factored that into your -- the value that you assigned to the net metering -- net metered energy.

A. Yeah, absolutely. As I walked through rebutting Mr. Owen's comments, I think there's eight different points, we address all of them. And anyone that actually has an actual avoided cost is absolutely included, including the load-based ancillary costs that I had overlooked in my direct testimony that he pointed out in his discussion that I then later incorporated. And distributions losses are also one of those that is included in the avoided-cost rate.

Q. Okay. Give me just a second here. Mr. Vaughan, on page 25 of your rebuttal, you describe solar energy as a commodity consisting of energy capacity and renewable attributes.

Do you recall that?

A. Yes, sir.

Q. You describe the Company's test year average capacity value and distribution value for a residential system at $515; is that correct?

A. That would be the -- I think you said "distribution," it would be energy and capacity.

Q. Oh, okay. And the average system, this average system is 8.84 kilowatts?

A. Yes, for the residential class.

Q. Okay. Producing 13,374 kilowatt hours of energy?

A. Yes, sir.

Q. Okay. And representing about 3.36 kilowatts of market capacity with the energy valued at the hourly PJM LMP and the PJM RPM; is that correct?

A. Yes. That table there on R25 could give you that, essentially what the commodity value is, yes.

Q. Okay. I'm trying to understand how it is informative to consider the customer-invested generation as a commodity to the PJM market, particularly for NMS I customer generators, given the very limited constructs granted to such localized small-capacity systems operating under statutory constraints and current PSC interconnection guidelines and operating behind the meter.

A. Can you repeat your question, please?
Q. Yeah. I'm trying to understand how informative it is to consider customer-invested generation as a commodity to the PJM market, particularly for NMS I customers, given the very limited constructs granted to such localized small-capacity systems operating under statutory constraints, PSC interconnection guidelines, and operating in a fashion behind the meter.
A. So again, NMS I customers are grandfathered, but again, it's informative because we're talking about a commodity here, and but for this DG -- the DG electrons that under NMS II, or under any construct, but for that, we're trying to come up with what is the commodity price that customers would have otherwise consumed that commodity at. And when you're looking at it on a purely marginal basis, that's what it is.
Q. Okay. On page 25 of your rebuttal, it appears that the NG capacity shown in the figure on that page considered solar's total generation and not the kilowatt hours that could be received by the grid from that customer generator; is that correct?
A. That's right. That's the full load shape. It's not -- it's not discounted for what would be

consumed behind the meter. As I state here, there's, like a generator view of that commodity.

Q. Okay. And so you're -- are you suggesting that the kilowatt hours that are generated by the customer generators' systems are instantaneously used behind the meter -- that aren't instantaneously used behind the meter should be viewed as a commodity and valued at commodity value as well?

A. For the -- for the purpose of setting the correct rates for net metering customers and how it affects other customers, yes, any avoided costs should be taken into account. The avoided cost is the commodity price.

Q. Okay. How do you square the revenue meter as being the demarcation point where the kilowatt hours suddenly become a commodity at the PJM hourly LMP price?

A. Well, again, when we -- when we produce the avoided-cost rates, they account for things like distribution losses. So you're grossing up what the price would have otherwise been. You know, you're getting a credit for distribution losses because you do you travel from your regular net distribution, that meter, up to a -- your -- the price from PJM is a transmission-level price.

So I'm not saying the customer is selling some commodity or doing anything like that. It is purely a marginal cost of service exercise when you're looking at what an increment or decrement of load or generation is worth. It's very standard.

Q. Okay. Shifting gears for a second. You are familiar with the -- we -- getting back to the K-PEGG program. You didn't like the word "subsidy," but can you tell me, in your understanding, what is the justification for imposing a $12 annual cost on existing commercial customers to fund potential economic development for future customers?

A. Well, I think as Company Witness Wiseman and Company Witness Mattison have discussed, you know, our -- they discussed our economic development efforts. And as I show in AEV Exhibit 9, when we are successful there, and when those programs work, we reduce everyone else's rates by attracting new customers and increasing the denominator in the billing equation. And so I hope our current commercial customers are future commercial customers, and these economic development programs are trying to help encourage that.

Q. Okay. And you're familiar with the TEE program, the Targeted Energy Efficiency program and

the funding mechanism for that?

A. Only at a high level.

Q. Okay. Okay. I'm not going to ask you any more about that, then.

The TEE program, the Low Income Energy Assistance program, and the K-PEGG program seem to have in common the idea that -- leaving aside questions, particularly with Low Income Energy Assistance, that we are a moral people who see the importance of helping out those who are -- who are less well-off than we, they seem to have a common element, and that is that the cost of those programs are spread across the entire customer class, but the benefits may inure to a select number of people within that class at a higher level than they are generally benefitting the whole class; is that correct?

A. Again, setting the K-PEGG aside, the energy efficiency programs there, to the extent -- definitely the people receiving those program dollars and whatever benefits come with it, right, they're receiving those benefits, but to the extent -- to the extent you're lowering that load on a cost-causing peak, cost of service is benefitting. And no, I have no analysis showing any correlation

there, what the actual programs are.

And then, you know, we talked about the heating assistance, the low-income assistance programs, right? That's funded with various ways, through some shareholder dollars, through some federal dollars, through some contributions from customers, and that's just -- that is what it is.

Q. Okay. You know, it seem -- and the reason I ask these questions is not just to be cute. Okay? The reason I ask is because it seems that Kentucky Power doesn't have a philosophical opposition to having subsidies within a class of customers provided that it believes that there's some value gained from it. It doesn't even seem to have an economic problem with interclass subsidies. And I'm just trying to, for the life of me, figure out why it is so obsessed with wanting to prevent a supposed subsidy from a handful of residential customers that are of negligible impact to the remaining members of that customer class.

MS. BLEND: Your Honor, objection as argumentative and because Mr. FitzGerald has now, it appears, begun testifying through his cross-examination.

CHAIRMAN SCHMITT: Sustained.

MS. BLEND: If Mr. FitzGerald could --

CHAIRMAN SCHMITT: Sustained. Sustained.

Q. If we could, Mr. Vaughan, I'd like to ask questions about mechanism of the NMS II tariff.

The existing tariff, as I understand it, is a one-to-one credit, one kilowatt hour generated and fed into the grid, one used, they net out; is that correct?

A. Over a period of time, yes, right. But it's not instantaneous. It's -- they get to use their bill as if it were a battery, and that is the old volumetric construct that has been stricken from the law.

Q. Okay. And -- well, that's not for grandfathered customers, right?

A. I'm sorry. Can you say that again?

Q. Not for grandfathered customers it hasn't been stricken from the law?

A. That's right. For the grandfathered customers, it is still in place.

Q. Okay. And are you proposing an instantaneous tariff or are you proposing one that nets over a period of time as well?

A. Right now, this is a period of time. It's just we're narrowing that period of time to keep it

within actually when the systems are producing, right? It's not -- it's not to instantaneous yet, and, you know, we could potentially look at that in the future, but right now we're just taking the measured step from full volumetric, where a customer could produce a kilowatt hour in the middle of the afternoon then net it on a winter morning peak when there's no sun out, to something that at least nets within the solar production window.

Q. Okay. But it's still being netted over a billing period?

A. It's being netted within the -- within the netting period and accumulated for the billing period.

Q. Okay.

A. Then start over.

Q. So am I correct that the NMS II requires customers to redeem credits for any excess generation within that same period during which the kilowatt hours were generated? Is that what you were mentioning? You termed it "narrowing."

A. Yes. It's going from all 730-ish hours in the month to the solar production hours, the majority of the solar production there that -- on the daytime on-peak period there.

Q. Okay.

A. Yes, they are netting within that. And as you accumulate the net, net excess energy in that period, at the end of the month they will receive a bill credit for that amount.

Q. Thank you. Thank you. We're on the same page. That's excellent.

Let me ask, Mr. Vaughan: Those credits carry forward, do they -- do they not, under your proposal, from a month-to-month basis?

A. No, they do not carry forward. They are on the customer's bill each month.

Q. Okay. So you're proposing that any excess generation that is -- occurs within a month and is not consumed within that same month would be extinguished?

A. It's not extinguished, it's being credited at the avoided-cost rate, because you're accounting for all the energy in that system each month, whether it is netted in one of the netting periods or it is excess energy -- net negative energy or excess energy, it's then being credited. So it's a -- it is a financial credit, as discussed in the statute, on the customer's bill each month.

Q. Okay. So --

A. If you --
Q. Go ahead.
A. If you look at -- oh, man. A lot of testimony pages here, sorry.
Q. No, that's fine.
A. If you look at my testimony, rebuttal testimony, R41, that table, on the NMS II bill example for that residential customer, there's a hundred-dollar rate billing, and then there's excess energy credit of 19 to a monthly bill of $81 there. And so at that point you've accounted for all system generation in that billing period, and then you start over in the following month at zero and you do the same.
Q. Okay. What if my generation within a billing period exceeds my usage? Do I have a credit that carries forward at that point?
A. No. That's exactly what the 19 is there. Whether it exceeded your energy in total or just within that billing period, any net negative excess energy is being compensated at the avoided-cost rate each and every month.
Q. Okay. Let's shift gears here. A couple of more areas I wanted to talk about. Did you -- are you familiar with the declining block rate proposal?

A. Yes, sir. I proposed it.
Q. Okay. Who is eligible for that rate under your proposal?
A. Who's eligible?
Q. Uh-huh.
A. All residential customers who have more than 1,100 kilowatt hours in the winter months will see some sort of benefit from that proposal.
Q. Okay. What's the effect of a customer's rate when they reach that level?
A. It's then reduced. There's a discount in that tail block, you know --
Q. Okay. So --
A. -- I referred in my direct testimony, to -- to reduce the interclass subsidy that's overpaying fixed costs that those customers are experiencing currently.
Q. Okay. So it cuts that party a break in terms of their costs of electricity above that level; is that correct?
A. It, per cost-causation, is reducing the interclass subsidy by reducing the applicable rate.
Q. Okay. So has the Company projected how many customers would benefit from the declining block rate?

A. I think -- I think it's in my -- it's in my testimony or it's in discovery responses, but, yes, it's a great number of customers.

Q. Okay. And have you calculated what effect that lower rate would have in terms of whether that customer, for the usage above that cutoff, whether they would still be paying their fair share of the fixed costs if they're getting a break on that overall rate?

A. Yeah, absolutely. That's why I proposed it that way. They're paying full distribution and transmission costs and then they're lowering a piece of the generation costs there that they're paying. So again, when you have as much fixed cost and volumetric rates as the Company does, you can see very skewed bills when you have high load months because of cold weather because that is nondiscretionary load, so you'd see a customer who is paying a very large piece of fixed cost because it got very cold for an extended period of time and their usage went way up, and that's what we're attempting to rectify, in part, here through the declining block in the winter.

Q. Okay. So where are they -- if you still are recovering all the fixed costs, where are you giving

them a break?

A. We're reducing their fixed cost contribution because they are overpaying to begin with. So we're bringing it more in line with what they should be paying. It's the opposite of the NMS proposal.

Q. Okay. If I am a customer who has installed energy efficiency measures in my house on my side of the meter, and because of that I'm using less electricity, am I contribute -- am I undercontributing to the recovery of fixed costs relative to these other customers?

A. I can't answer your question with just that. I mean, I need to know, like, how many billing kilowatt hours you use and whatnot, right, because it's all -- everything is based on averages, and, you know, you look in my testimony, our electric heating customers are using significantly above average because of those high winter usage months, and that's the issue.

And, again, as I mentioned, we have 90 percent of our total revenues in the residential class are in volumetric charges, so as you reduce usage through any means, energy efficiency or otherwise, you see some sort of reduction in bill there and reduction in fixed cost contribution.

Q. Okay. I'm always, Mr. Vaughan, in the unenviable position of standing between everyone and lunch, so I'm going to try to wrap this up in the next couple minutes.

A. Can you hear me? I just received a new microphone.

Q. Mr. Vaughan, are you familiar with the -- with the AMI initiative, the proposal?

A. Somewhat.

Q. Okay. I had asked before, and I don't know that the question was answered. Do you know if there's an empirical basis, a study or a set of studies, for assuming that getting energy information on usage more frequently would be a benefit to customers, and particularly low-income customers?

A. I don't know if there's any direct financial benefit to customers from receiving any more or any less information, but I think, you know, Company Witness West and Blankenship and everyone else who has discussed that AMI, you know, they all have their reasons for it, and there's -- you know, overall we need it because of the obsolescence of the AMR meters, and I think if you wanted to look at a direct benefit for potentially a low-income

customer, it's that flex pay program Mr. West discussed.

Q. Okay. And within the areas that you work, are you familiar with any utilities that have prepayment or split billing programs that don't use AMI?

A. I am not. I know Public Service Company of Oklahoma worked for the better part of a decade to try and implement a prepay program on AMR technology, and it was very difficult. I don't think it ever got across the finish line until we did roll out AMI there.

Q. Okay. Are you familiar with any studies indicating that low- and fixed-income customers of Kentucky Power have elasticity in their electricity demand and have opportunities for further reduction in usage based on that information?

A. You kind of flipped out there as you put your hand over your video. Could you repeat that?

Q. Yeah. I'm sorry. Are you familiar -- aware of any studies indicating that low- and fixed-income customers of KPC have elasticity in their electricity demand and have opportunities to further reduce their electric usage in response to getting more data about their usage?

A. No, I don't have any studies like that. And again, as I discussed earlier, I think a lot of the Company's load with the amount of electric heating customers we have is somewhat nondiscretionary.

Q. Okay. Residential customers like Tariff RS don't have demand charges and don't have time-of-day rates unless they are using that voluntary tariff; is that correct?

A. That's correct. If they -- what we would essentially call a two-part rate. You have a basic service charge and you have an energy charge --

Q. Right.

A. -- and the percent of revenue on the end of it, as we discussed with Mr. Spenard -- Mr. Spenard.

Q. Okay. And you're not proposing any time-of-day rates for all residential customers under the AMI initiative; is that correct?

A. No, sir.

Q. Do you know whether the Company has considered what an investment comparable to the cost of AMI in weatherization, replacement of housing stock with radiant heat, that has radiant heating, or other measures that would assist the customers to be able to use less would do in terms of actually allowing customers to lower their costs and better

manage their budgets?

Has there been any -- the assumption of the other witnesses, at least, is that, armed with this information, people would be able to reduce their usage, and you seem to suggest that's not necessarily the case.

A. Well, I think more customer information is always good. I think if you have more, to the extent you have discretionary load, you could make those choices, if it exists, right? But nondiscretionary load such as heating, cooling, those are what they are. I'd like to focus more, from a customer standpoint, on that flex pay program where you can give customers more options in how they are billed and how they pay for their bill.

But, no, I mean, it also gives us the opportunity to do more, if, in the future, you have a lot of interest in some sort of peak-reduction program or something, a smart thermostat program that goes with some sort of EE investment in the future, right, AMI helps enable those types of technologies.

Q. Oh, okay. And you're aware that all of the EE programs that KPC had have now been eliminated, other than the KT program?

A. Yes, sir.

Q. Okay. And the -- Kentucky Power has provided testimony that a formal cost-benefit analysis was not performed. In part, the testimony was that, quote, many of the benefits are not readily quantifiable, but that the customer reliability and cost-savings benefits are, quote, sufficient to support AMI's implementation, end quote.

How, without conducting a formal cost-benefit analysis, can the Commission be assured that the benefits will exceed costs?

A. Well, from my standpoint, I need billing information to bill customers and make rates, and to the extent that our meters are failing, we need meters. And obsolescence is the basis for our AMI proposal in this case, and, you know, as -- I'm not the metering expert, Mr. Blankenship is, and he discussed that our meters are obsolete. So regardless of what the overall costs and benefits are, we need meters to provide service. You know, Mr. Phillips, I believe, did talk about reliability improvements that could happen, you know, for faster restoration times and all that.

So if you -- if you're going to quantify that, you have to go and do some sort of broad-based

economic study and say what is the value of the Company's grid, how much does an interruption of that service to the service territory reduce total economy, and, you know, we haven't done anything like that because, again, it's the Company's position we did not need to because its infrastructure is obsolete and needs to be replaced.

Q. Okay. But there are other alternatives to going with AMI technology, are there not?

A. I think there's that guaranteed most-cost road that Mr. Blankenship discussed, where we could upgrade to another breed of AMR and then subsequently upgrade to AMI as it goes away.

Q. Well, when you put AMI in place, you're going to subsequently have to upgrade and replace it as well, are you not?

MS. BLEND: Your Honor, at this point I'm going to object. This is far outside the scope of Mr. Vaughan's testimony in this case, and as he's explained repeatedly now, he's not an expert with regard to metering technology. That expert was Company Witness Blankenship, who has previously testified.

CHAIRMAN SCHMITT: How much longer do you have, Mr. FitzGerald, before we --

MR. FITZGERALD: Actually, this is the last question, Mr. Chairman.

CHAIRMAN SCHMITT: Well, can you answer the question -- the last question, Mr. Vaughan?

A. Can you repeat it?

Q. Mr. Vaughan, the -- you referred back to Mr. Blankenship's testimony as being -- the high-cost alternative would be going to an -- the AMR technology with the SCM Plus and then having to upgrade to AMI. Is that fair?

A. Yes, sir.

Q. Okay. Do you know what the useful life of the AMR with the SCM Plus meters are?

A. I don't know the AMR SCM Plus, what the useful life there is. I know we assumed from the manufacturer a 15-year useful life of the AMI meters and that's what was incorporated into my GMR revenue requirement calculations from a depreciation standpoint.

Q. Okay. So at some point they will have to be replaced too; is that correct?

A. Yes, with whatever the next thing is, but yes, we require metering infrastructure. I totally agree.

Q. Okay. And I will leave it at that.

MR. FITZGERALD: And, Mr. Chairman, I appreciate your indulgence.

Mr. Vaughan, I'm sorry if I was testifying when it was your turn up, but I appreciate you have been the cleanup batter.

And I am no longer standing between everyone and lunch. Thank you, Mr. Chairman.

CHAIRMAN SCHMITT: All right. We will now be in recess until 1:00 p.m., at which time Mr. Miller or Mr. Childers, on behalf of Sierra Club, will be -- have the opportunity to cross-examine the witness. So thank you.

(Recess began at 12:06 p.m.)

CHAIRMAN SCHMITT: Okay. Mr. Miller, you may begin your cross-examination.

CROSS-EXAMINATION

By Mr. Miller:

Q. Good afternoon, Mr. Vaughan. How are you?

A. Thank you. Doing well.

Q. Great. Matt Miller with Sierra Club. I don't have too many questions in light of extensive lines that have been posed to you already.

First question, I just want to confirm did I hear you right, when you were speaking with Spenard, that if and when there is some form of carbon

pricing that's instituted, at that point the Company would need to recalculate whatever the prevailing net-metering tariff concerning generation costs exists at that point?

A. Yes. Again, it depends. It may be automatically included, right? If there's a carbon adder in PJM or some sort of a carbon tax that affects the LMPs in PJM, you know, by essentially creating a higher dispatch cost or fossil units not flowing through the marginal cost of energy, I think it would be automatically included.

But, again, I'll go back to my RGGI example earlier. If it is some sort of carbon cost that is load-based versus source-based, yeah, I think definitely we would want to -- the intention is to fully include the actual financial avoided costs.

So, again, in that RGGI example I gave, in our Virginia company, right? Doesn't matter what the company is loading, matters what the sources are for carbon tax or charge based on that. So the customer reducing load doesn't reduce carbon cost. But, if there was some sort of load-based carbon charge, then, yes, you'd want to include that in the avoided cost rating.

Q. Very good. I want to ask you if -- well,

I'll circle back to that.

You were discussing, I believe with Mr. Fitzgerald, statutory provision that permits utilities to cap new net-metering customers when cumulative generating capacity of net-metering systems hits 1 percent of the company's single-hour peak load?

Is it your understanding that that is a mandatory cap, or could a utility choose to offer net metering beyond that 1 percent if it wished? I'm not asking for a legal conclusion, but just your understanding.

A. Obviously, I don't have a legal opinion there, but I believe the words say "the Company shall have no further obligation."

So, I mean, again, what one person may look at that as we can do it on our own, the Company, and some may say that the Commission has to approve that or the Commission would weigh in on that, but --

Q. And that's totally fair. I'll just ask you did you ever consider, or were you ever asked to consider allowing to design a tariff or otherwise to plan or consider what the Company's offerings would be if the 1 percent cap were not imposed?

In other words, are you aware -- did you ever

consider or were you ever asked to consider what differences in any there may be for the tariff if the 1 percent cap were not imposed?

A. Right. I think definitely consider that. I think you can look to our current tariff book to see what that might be. Right now a customer that puts in a distributed solar resource doesn't have to be a net-metering customer. They could sign up for a cogen STD tariff as a coal power producer and sell the output of a facility based on that.

So, you know, essentially, as I mentioned in my direct testimony, these are essentially PURPA QF projects. You know, they're small power facilities, and some sort of avoided cost rate like that of a PURPA rate would make a lot of sense.

Q. Okay. What is your understanding of why the 1 percent cap is being imposed? Is it just that it is permitted by the statute, or is there an affirmative reason why that makes more sense for the Company and its ratepayers?

A. No idea why the legislators put that in there.

I was not in the room.

Q. And sorry. Just so I'm clear. Not why was the statute passed by the legislators, but why is

the Company -- just assume for a moment -- and, you know, not holding you to this interpretation, but assume that it is a permissive, not a mandatory cap. Are you aware of any reasons why the Company is choosing to impose the cap apart from it being allowed by the statute?

A. Yeah, I get you. I mean, I think if net-metering rate design evolved to the place where everyone was truly indifferent, then there would be no reason to, but if, you know, that's what we're moving forward to with NMS II where you're compensating at avoiding cost rates for that excess generation.

There's still some netting in there where you're volumetrically netting billable kilowatt hours, and there could still be some financial inequalities there.

So in theory in the future, if you got to where you're indifferent to whether a customer takes service under NMS, whatever it is at that point, and cogen SPP, I don't see why you would choose one or the other.

Q. I see. So am I understanding your meaning correctly, when you say "indifferent" and implying that it's not indifferent now, that even when the

Commission approves -- you know, either approves or institutes a new net-metering tariff under the statute, is it your contention that there would still be some subsidization that would still be occurring?

You know, at the end of this case that means the Company still wouldn't be indifferent even after the Commission, you know, approves the new rate. Does that make sense?

A. I mean, it's -- you know, like we talk about in all those high-level rate design principles -- gradualism and taking steps towards cost causation and all that, we're taking steps to remove subsidy. We're not getting all the way there. It depends on whose subsidy you look at.

Obviously, you look at AG KIUC Witness Baron's -- what he thinks would be the way to skin it would be to go at a buy all/sell all. Right? Where you would sell at an avoided cost rate, like QF PURPA rate, and then you would charge the customer full retail load.

Ours is definitely between that and the old volumetric 100 percent of the retail rate, and the reasons I say there is -- ours being an NMS II proposal or somewhere there in the middle.

And the reason I say there would still be some -- there's still some level of subsidy there because of the sheer amount of distribution, you know, wires, fixed cost, infrastructure costs we that including volumetric rates. Right? So maybe rate design evolves over time, you know, and it eliminates some of that as well, but as we sit here today with 90 percent volumetric charge, you know, a lot of fixed costs in there, there's still some level.

Q. Thanks. So it sounds like you were listening in when Mr. Mattison testified last week. He said at one point -- great. Something along the lines of Company's rates -- the Company taking into account customer's ability to pay as well as AEP's carbon goals and that the Company believes that its rates should reflect these.

Do you recall that? Does that sound accurate at a high level?

A. I remember the discussion, yes.

Q. Okay. I'm wondering -- well, first on -- on jobs and customers' ability to pay and the local public interest, is the EDR rider the only mechanism for taking into account customers' ability, or does the kind of the tariff in chief also meant to factor

that in? Do you know what I'm getting at?

A. Factor what in?

Q. Well, sensitivity to customers' ability to pay. What I'm trying to get at is kind of an analogy.

Were you listening when Witness McKenzie was testifying about rate of return?

A. I was listening, but there was --

Q. And I don't mean to characterize that testimony too much, but there was a discussion about whether -- you know, his testimony kind of crunched the numbers, so to speak, indifferent to considerations that the Commission might take into account in fashioning rates, including customers' ability to pay.

And he said we're providing the numbers within the confines of, you know, this market analysis, and then the Commission can do what it will in fashioning rates that might be more realistic or take other things into account.

A. I think his testimony was that he was providing his expert view of what the cost of equity capital is.

Q. Very good. More precise.

And so I'm trying to get, analogously, in your

rate design, apart from -- you know, before getting to the EDR rider, does -- is -- is the, you know, cost-of-service analysis and then the rate that is proposed, the tariff that's proposed based upon that, is that strictly kind of based on, you know, just the cold math about the classes and their shares and subsidies and not, you know, what I might call more public interest considerations, customers' ability to pay, and that kind of thing?

A. So I won't refer to it as cold math since I math all day every day. It's very near and dear to my heart.

But, no, the revenue requirement is statutorily driven, you know, minimum filing requirement, accounting, financial-data type calculation. You know, it is what it is.

And then I think when you look at customers' ability to pay, you have to look at the total suite of what we have proposed in this case between the various mitigation measures, the first-year offset, the discussion that I had earlier with several folks about where our rates have gone down over time, and, if we were to get our full ask in this case, we're kind of getting back to where we were four years ago, and that wouldn't go into effect for another

year.

So all those things are taken into account when you're thinking about ability to pay and what's going on right now in the territory and the world in general with the pandemic.

And on top of that, you look at our rate design, and I know we fundamentally disagree on a lot of things like service charges, but we are looking at all customers, and we have a lot of customers that are paying more than their -- their share of the fixed costs contribution for things like distribution infrastructure, you know, with the heavily weighted energy rates.

So moving -- moving the fixed charge up to what -- the basic service charge increase to kind of be in line more with our peers and the winter declining block to help some of those electric heating customers that are paying that disproportionate share of fixed cost contribution in the winter months when their usage spikes. I think all those things in concert go into what we're looking at from a cost-of-service rate, affordability, everything.

Q. That makes sense. Now, I just want to see if I have it right. Is it correct to say, then, that

-- so let's say we're thinking about in a local economic impact -- oops.

Okay. You know, local economic challenges for a class of customers, say, is it right to say that the standard tariff in chief for residential customers at large, let's say, does not factor that in, but that there are other programs; there are, you know, payment plans, there are DSM, there's the EDR rider, that these things kind of come in on top of that to get at that concern at the local economic situation or -- is that -- is that fair to say?

A. In part. Another -- another portability measure we looked at here in Witness Baron, AG KIUC, also discusses it, our class cost of service study shows that there was a fairly large subsidy being paid to the residential class, and that crops back up in our -- that our industrial customers are paying that.

So would we have liked to have reduced that subsidy in this rate case? Yes, we'd like to move towards cost of service there, but because of the affordability and the other issues we discussed, we chose not to, and, you know, Witness Baron discusses that. And he -- he had, you know, a similar conclusion that now wasn't the time to do that.

You know, that's a hard decision, especially when you have that higher cost in your industrial rate as you're trying to attract more businesses, service territory, and retain existing business that provides jobs and a lot of economic benefits in the service territory. You know, you got to look at all those things. And that was a hard decision around affordability that we made in this rate case.

And you are correct, there are other tariff provisions that also try and address affordability, your payment plans. And, hopefully, Mr. West's flex pay in the future and, hopefully, the EDR tariff keeps attracting new business, and that grows. But yeah.

Q. Okay. Okay. Good. That helps me with affordability and jobs.

Let's take another issue or two that, you know, aren't as squarely in the traditional, you know, obvious core of ratemaking perhaps. But let's say the Company or the parent company wants to make strides on public health. They have concerns about children's asthma or our own climate. And they have these goals, and they want to -- say they want to move away incrementally from fossil-based generation.

And then that can have, you know, a direct financial calculation too in terms of the Company attracting institutional investors. And we've heard some testimony about that.

So let's say that they want -- the Company wants to do this. Does that ever get built into rate design as opposed to just -- I imagine it would when the Company is making resource planning decisions come into play. What do we do with this fork in the road with a plan that we may have or our needs for generation, but is it additionally ever built into rate design, for instance, incentivizing more clean distributed generation, or could it be?

That was a long-winded question.

A. Yeah. Let me try and answer for you. So we -- in rate design and cost of service we include cost of service and rate design items, so if there is a sort of fungible cost that is incurred or can be avoided, that's always considered. Or like the Company's affiliate outlets, PEBCO and PSO who are going to -- they're putting a $2 billion wind farm to help serve their resources going forward. Obviously, that -- all of the cost and benefits of that are going to be in its rates, you know, follow through in rate design, you know.

And we don't -- in my experience, we don't include things that are not a quantifiable cost of service, you know. We generally would rely upon, you know, state and federal folks to incent that such as they do outside of our electricity rates, you know, unless told otherwise.

Q. I see. And so things like public health or climate benefits would not be, in your opinion, a kind of quantifiable cost of service in that sense?

A. We don't get a bill for what the residential class incurred for X public health charge. You know --

Q. Right.

A. -- that's not part of our electric service.

Q. And is it right, though, also, that affordability for customers or economic development, job creation or job maintenance are not quantifiable cost-of-service items either?

A. No, that's totally incorrect. As I discussed with Mr. Fitzgerald there, let's look at AEV Exhibit 9, you know, rates are lower by a quarter million dollars a year because our EPR tariff worked, and if we have more success there, rates will continue to go down.

I've worked on -- we have, as was mentioned

with Mr. West, we have a federal contract to preserve a customer that was a main off taker or main feed dock to AK Steel to help keep them in the service territory. And, you know, had we not done that, customers would be paying millions of dollars more for electric -- for their electric service because there's fixed costs associated with that load. And, as it goes away, we spread those over to fewer people. (Indiscernible) quantifiable.

Q. I see. So insofar as you can quantify them through something like that, like the additional retention or loss of customers that affect -- of electricity customers that affect rates, and that is included, but not -- and you can confirm -- something that's a little -- it's perhaps not quantifiable, but it's certainly a compelling thing, like just general hardship among the population, you know, the concern apart from its impact on the customer base, things like job loss, that kind of thing; is that correct?

A. Nothing beyond what I've already discussed, no.

Q. I see. That's helpful.

MR. MILLER: I think that's all I have, Mr. Vaughan. I appreciate you talking with me.

Have a great afternoon.

CHAIRMAN SCHMITT: Mr. Frye, any questions?

MR. FRYE: I have no questions, Mr. Chairman.

CHAIRMAN SCHMITT: Vice Chairman Chandler, questions?

VICE CHAIRMAN CHANDLER: Yeah. Thanks, Chairman. Can you hear me? Can anybody hear me?

EXAMINATION

By Vice Chairman Chandler:

Q. Mr. Vaughan, can you hear me?

A. Yes.

Q. Okay. Great. So it's been a long day. I have a lot of things left over. I don't know if you know this, Mr. Vaughan, but Post-it notes are made almost exclusively in the state of Kentucky. And by the look of my desk, I robbed them over the weekend.

So I have a lot of little notes that are left over from questions I asked other people or leftover follow-ups I have from where other people asked you questions.

A. I take scribbles.

Q. It's about what mine look like. So I'm going to jump around a little bit. So bear with me. If you need -- you know, if you have no idea what I'm talking about, that probably makes two of us.

So the first place is do you remember Ms. Whitney's testimony earlier -- can't be earlier this week -- last week on OPEB and pension prepayments included in the cost of service in this case?

A. Yes.

Q. Okay. And do you remember me asking her questions about how, you know, that -- that there was a prepayment in existence when the Company filed its 2017 rate case? Do you remember that?

A. I do remember that, yes.

Q. Okay. And I think -- and correct me if your memory is different, but as I remember it, Ms. Whitney said that they were in existence in 2017 and that they would have been holistically considered, both the pension and the OPEB, in the capitalization, but not necessarily -- they weren't, as I understand it, reflected in the rate base in that case.

Is that your understanding as well?

A. So the -- I believe that's correct. It's holistically included in the capitalization. I do believe the pension asset was included in the rate base in that case, but the OPEB might not have been explicitly due to it was fairly small at that point.

It would have been one of the differences between -- in total between the overall capitalization and the overall illustrative rate base in that case.

Q. And that's what I want to ask about, is the difference between those two. So you're right. I understood that pension was noted as a component of rate base, but OPEB was not. Are we on the same page with that?

A. Yeah, I think that's fair.

Q. Okay. So how is it that rate base and capitalization reconciled in the 2017 case if the OPEB was not identified as a rate base component in that matter?

A. When you say "reconciled," they didn't equal, but when you then look at all the other balance sheet amounts, there's something in there that brings the two together. So it would have been a reconciling item in that other balance sheet amount to get you from capitalization of rate base, rate base to capitalization.

Q. Yeah. And I understand that they don't necessarily equal, which is why you reconcile them, right, you note the differences. My question is why wasn't OPEB noted as a difference between the two?

A. I would assume it's in a larger variance,

some other category of accounts that's in there and noted as a variance.

I mean, it's definitely part of the difference if we didn't include it in rate base. They're both capitalized cash assets on the company's books and included in capitalization. So it just wasn't -- it was pretty small at that point in time, so it was probably not picked out as a subset of some other balance sheet category that wasn't included in rate base.

Q. I believe the pension remands were included as a discrete rate base item. Is that your understanding?

A. That's -- that's right. They were much more material. I can't remember how many millions, but it was much larger.

Q. Okay.

A. I think OPEB started out small, and it's been growing since that time.

Q. Look at us, making progress already. Okay.

So second item. I just want to make sure that I'm clear from, I think, a couple of questions you were asked earlier about the only difference -- this is what I'm understanding here -- the only -- as it relates to base rates, the only change on

December 8th that will occur in terms of the costs the Company incurs as it relates to the UPA is the reduction of approximately $57.4 million in expenses in Account Number 5550027.

Is that your testimony?

A. Yes, Your Honor. That's the adjusted test year amount that's in our rates in this rate case. That's the demand. That purchase power account there you just quoted is the purchase power demand portion of the UPA bill.

So and again, just a quick distinction there, that there's a portion of that in base rates and a portion of that included in environmental surcharge (indiscernible) point.

Q. Yeah. And what I want to make clear, the environmental surcharge will true itself up, right? That savings will fix itself.

I'm asking specific to if the Commission does nothing, right, just lets things stay the way they are, there will be that $57.4 million reduction in test year expense that the Company will no longer incur. Correct?

A. That's right, but it's already been fixed in the settlement in the last rate case, the 2017-00179 to the fixed cost savings.

Q. And that's what I want to get to. And so correct me if I'm wrong, but as I understand it, to the extent the Company is not earning its authorized ROE in that following calendar -- is it that following calendar year that it's related to or the 2020 -- 2022 that it's related to?

A. It's just in 2023, the following calendar year after the UPA expires.

Q. Okay. So I guess the first question is that doesn't speak to that -- let's call it 23 days, right? That the Company will continue to recover that cost, recover that amount through rates at a 23-out-of-365 rate, right, when they don't incur the expense for 2022. Is that right?

A. I don't think that's entirely true. I think the way the words are in the settlement agreement is that would begin going into the PPA deferral calculation at that point. I think you get the -- right, you're going to be, oh, 20 -- 23/31st of that there in December.

Because there's deferral accounting balance of PPA each month. So you're going to start accruing a credit for that fixed cost reduction when it happens, and the only difference is that there in 2023 there's that one-year provision for the Company

to use a portion of that fixed cost savings to earn its Commission-approved ROE.

Q. Okay. That's what I want to get to. So there will be a savings of $57.4 million for the calendar year 2023, assuming base rates stay the same, right?

Assuming there's no change in 2021 or 2022, the proposal from the case that was adopted, the settlement, is that that 57.4 will be used by the Company to earn its authorized ROE, and the remainder, if it earns its ROE from -- let's say they need 20 million of that amount to earn its ROE, and there's excess, that will be flowed back to customers through tariff PPA. Is that your understanding?

A. Again, taking the environmental surcharge into account. I don't know how much of that is in there, if that happens automatically, but yes, during 2023, if the Company is $5 million short of earning its allowed ROE, the way that settlement and the PPA forms are set up to work is that first 5 million, then, would go to increase the Company's ROE, the authorized, and the remainder of the fixed-cost savings would flow through the tariff PPA to the customers as a credit.

Q. Okay. So I want to come to the second part of that which is -- sorry. I'm marking things off as I ask them.

How does the Company calculate its earned ROE in between rate cases?

A. So it is -- for that purpose right there, you have GAAP, and you have ongoing, and all the reporting measures, but there's actually -- in the Commission-approved forms for a tariff PPA, there's already a calculation set out in there, and I do not remember it offhand. We can (indiscernible).

Q. Yeah, let me ask this question: If the Company -- if the Company is denied cost recovery for -- I'm just going to make up a number, right -- for -- well, the AG's office has proposed an additional adjustment for EEI dues. You're aware of that, right?

So just hypothetically the Commission denies all EEI dues at some certain amount, a test year amount, right? And in 2023 the Company actually incurs its -- the entirety of EEI dues, right? They continue to participate in EEI as a member with AEP, they continue to get costs allocated to it, and they write the check for it, right?

When the Company is calculating its actual

ROE, are they doing it on the basis of assuming the amounts that were denied recovery from the Commission, or do they include those in their calculation?

A. I'm not a hundred percent sure that that was contemplated in that calculation. And, honestly, I would need to go back and look at it, but I'm just not certain at this time.

It's in the forms that are approved by the Commission. I would need to look at what that is for tariff PPA. That actual calculation is already laid out that, you know, based on the facts, that settlement at that time, that was the deal going forward.

Q. Do you understand the -- sort of the background of my question is that --

A. I get what you're saying, yes, sir.

Q. -- 2023 it will be immaterial what the Commission denied in recovery for this. It will only matter what the Company actually incurred in terms of costs.

A. Yes, sir.

Q. Okay. And on that note, you were throwing out a 5 percent number earlier in terms of the Company's actual earned ROE over a certain time

horizon.

Do you remember that?

A. Yes. That's from Company Mattison's rebuttal testimony.

Q. Yeah, and does the Company calculate that on the costs actually incurred or the costs allowed for recovery by the Public Service Commission?

A. I'd -- the basis for its calculation is -- I did not do it, but I would assume it's like a GAAP view. So it's going to be what the Company actually has financed, you know, for providing utility service and then what its actual costs and revenues are, so it's an as-incurred as-received basis.

Q. Okay. And that's an important distinction, isn't it? Because if the Commission denies -- I'm making another amount up here. If the Commission denies some costs, right, whether it's a pension cost or a somebody's salary, and the Company continues to go ahead and incur it and just decides that it's worth it for the Company to continue to incur that cost even if you don't get base rate recovery, is it your understanding that the Company will continue to calculate their earned -- actual earned ROE, including that cost, in the calculation?

A. Yeah, it's actually the costs we're

incurring, so it would be included in the Company's return.

Q. Would you agree that that's a disconnect, then, when the Company states what its earned ROE is versus what its allowed ROE is, that one includes costs that the Commission explicitly did not allow for recovery of?

A. I don't necessarily think it's a disconnect. I think it's a compromise based on the facts in that case and the amount of fixed costs from that UPA that are in the base rates, right?

I mean, if -- but for that settlement agreement, the Company -- let's just assume -- let's assume we're earning at our earned ROE and, for some reason, we wanted to make a windfall going forward at that point. We could just stay out until someone complains and we come in.

With that settlement, customers get the benefit of reduced costs from day one when that happens. You know, everyone talks about regulatory lag and drag. That's just the other side of it. In this way, based on that settlement at that time, the Commission approved at this point, the customers get that benefit day one. So I hear what you're saying, Your Honor. I don't -- I think it's a compromise.

Q. I just want to be clear. I'm not even asking anymore about 2023. I was saying -- I was asking about Mr. Mattison's testimony where he talks -- he talks about specifically what the Company has earned over the last year or two.

But you would agree that the Company is most likely incurring expenses that the Commission found unreasonable for recovery in rates, right?

A. I totally disagree. I do not think we have anything in our rates that has been disallowed in the past.

Q. So there was nothing in the last settlement that was removed as an adjustment to test year expenses that you think the Company has continued to spend?

A. Nothing that got removed in that settlement agreement that was approved by the Commission at the time was deemed to be unreasonable or imprudent. It was just removed for purposes of that settlement, and everyone that was a party to that settlement had the opportunity to come and relitigate those issues in the next rate case.

Q. Yeah, but what I'm saying is those were removed from rate recovery from customers, right?

A. As part of the compromise in the settlement.

Q. Yeah, and I'm not talking about any of that. I'm saying that the Commission determined rates that were calculated not including specific expenses, correct?

A. Yes, Your Honor. And a good example of that is the Company, as part of the compromise, decided to not -- you know, to essentially take to the bottom line 20 percent of FERC-approved transmission charges as part of the compromise. It doesn't mean they're imprudent or shouldn't be incurred or that we don't have to pay for them. It's just it was part of the deal that got everyone, besides the AG's office, to yes on that settlement agreement.

Q. Yeah, but that's not what I'm talking about. I'm saying in this case, let's say that the Commission decides that the Company can't recover the expenses to mow the yard at -- or the lawn at AEP, Kentucky Power's headquarters, in Ashland, right?

It's a $50,000-a-year expense, and the Commission says it's unreasonable, and you should let it grow, right?

That is an expense that the Company is going to continue to incur moving forward, right? If they continue to mow it, that's 50 grand it will -- will

be a cost, but you would agree that the Commission denied that for rate recovery, right?

A. Certainly.

Q. Okay. And so assume all things equal, right? And that but for that $50,000, the Company was going to earn its authorized ROE in the next calendar year, right, but they couldn't -- but I'm just saying -- but I'm asking, when the Company calculates on a GAAP basis their earned ROE, right, are they taking out that 50,000 from the calculation, or do the rates -- are their rates insufficient to have a 9.5 percent ROE because it was denied recovery from the Commission?

A. Yeah, I think that hypothetical $50,000 of mowing expense is included. It's a drag on the ROE.

Q. Okay. That's what I want to make sure. So when a company says that it hasn't been able to meet its ROE -- when Kentucky Power says it hasn't been able to meet its ROE, I just want to make sure that I'm clear that it's not removing from that calculation those costs that the Commission denied recovery for.

A. I'm not aware of any costs the Commission has denied recovery for, sir.

Q. You're not --

A. (Indiscernible.)
Q. You're not aware of any expenses in the last rate case that were removed pursuant to the settlement?
A. Sir, my -- Your Honor, my position is that everyone compromised in that settlement, and certain costs were removed. As part of the overall compromise, certain costs were added, certain costs were removed. And nothing was deemed imprudent. Nothing was disallowed.
Q. I'm not talking about anybody deeming things imprudent. I'm specifically talking about costs not being included in the determination of the revenue requirement. Does that make sense?
A. No, you're absolutely right. Rates were lowered by those amounts because of the compromise, yeah.
Q. But insofar as the Company continued to incur those costs, they were not reflected in the Company-approved revenue requirement, right?
A. Yeah. Absolutely. That's why it's one of the reasons the ROE is low, and that's why we're here talking last week and today.
Q. And that's what I want to make sure of, is that when you say a 5.something ROE, when Mr.

Mattison is discussing a 5.something ROE, that is inherently -- insofar as the Company is incurring costs that are not -- that were explicitly not included in the Company's most recent revenue requirements and thus not reflected in its rates, would you agree there's a disconnect?

A. Yeah, there's a small disconnect, like served and whatever other items that were removed or reduced in the last rate case. I think incentive pay was reduced a little bit, again, to get all parties in agreement there. Those aren't material -- that isn't the $70 million that we're here looking -- looking for, you know, from the base rate increase standpoint to get us up to the Company's proposed authorized ROE.

But yes, you're right to the extent, everything else being equal, those costs were not in the rates that the Company put in back in 2018, so those revenues are not contributing towards the earned ROE right now.

Q. I just want to -- I'm not asking about anything specific or -- I'm trying to figure out how the Company, in between rate cases, determines what its earned ROE is and whether it relates back to the approved rates, and so that is very helpful on that

issue.

A. It also relates to the test year, you know, level of sales and whatnot. You know, the Company was hoping for more balance from economic development between rate cases last time, and that wouldn't have been included in our sales level. So we took that risk hoping we were going to grow a billion units, and not all of it panned out in time. So --

Q. I appreciate that. Again, I'm just trying to figure out how it's calculated in the interim or what's taken into account. Okay?

A. Yes, (indiscernible).

Q. Say that again?

A. It's as earned, just like (indiscernible).

Q. Just straight math. Okay.

And on that -- on that, are you aware that the Company has proposed to the Commission a deferral of storm expenses incurred in the year 2020?

A. Tangentially. I was not involved in that filing.

Q. Okay. But I guess my question is -- and just to relate it back -- insofar as the Company is asking to defer storm expenses that were incurred in a year, those are currently expenses until the

Commission defers them, correct? Or grants deferral?

A. Yeah, unless -- unless we have permission to defer them, they are expenses on the books, you're correct.

Q. Okay. And so insofar as they're currently expenses on the book, those would be a drag to ROE, but that would -- a deferral order -- or an order deferring those amounts would change that calculation on a year-end basis, right?

A. Yeah. All other things being equal, if you defer costs, return should go up.

Q. Okay. Do you remember -- and I think I've asked -- maybe you're the third or fourth person about this -- the electricity sales in other states?

A. Yes.

Q. Have you scribbled anything down or do you have anything to refer me to on answering the question of why did Kentucky Power explicitly incur sales expense for sales of electricity to -- let me find the reference here on my notes -- Michigan and Illinois?

A. Yes, Your Honor. So, first, if you look at Section 5, Schedule 2, page 2 of 3, it shows the computation and the weighting of that state tax

rate.

And so just under 1 percent of the proposed state tax rate from the test year is Illinois and Michigan. 88 percent is Kentucky, and 21 is West Virginia where the Mitchell Plant is located.

And that small piece of Illinois and Michigan is based on sales the Company makes in PJM. And PJM supplies the tax department with the information there that they need to file those state -- income tax returns in those states.

So it's information provided by PJM to the Company that triggered that less than 1 percent weighting of Illinois and Michigan tax in our state tax rates.

Q. Specific to Kentucky Power?

A. Yes, sir.

Q. Okay. So if we ask for that, could you provide that documentation, the billing from PJM?

A. I can't, but someone in the tax department can provide whatever guidance we received. So there's no billing, right? We received information that we then used as the basis for a state tax return.

Q. Well, so the other question I have on that is do you know if sales tax is included, or is

includable, in Kentucky Power's energy bids at PJM, the cost-based bids?

A. These aren't sales taxes that we've been discussing. These are income taxes based on sales.

Q. Well, excuse me, income taxes based on sales includable as a line item expense in cost-based offers with PJM?

A. It's been a long time since I have looked at the -- the task force documents for cost-based offers, so no, I do not know. You can certainly include that in the market-based offer. I know that for sure, but I do not know.

I would assume if there is an applicable tax on, you know, fuel supply, it would be includable in a cost-based offer, but I guess I can't say with certainty just generic sales taxes.

Q. Let me ask this: If we asked a posthearing data request on that, could somebody at the Company provide that?

A. I'm pretty sure I could make Witness Stegall provide one on that, yeah.

Q. I appreciate it. Were you watching the hearing when I talked to -- and I think it may have been Witness Wiseman and Witness West -- about the -- the Company's data request responses in Case

Number 2020-00085 on customers' on-time pay percentage during the months of 2020 as compared to those '17, '18, and '19 averages?

A. Yes. And I think you're -- is that what we've been referring to as the debt forgiveness case?

Q. No, that is the Commission's -- the Commission's docket -- general docket on COVID where the Company was asked to provide what the on-time pay percentage for each class was in the past three calendar years and each month of 2020.

And do you remember conversations with -- that I had with -- not specifics -- that I had a conversation with Ms. Wiseman and Mr. West on that issue?

A. Yes. More recently, Mr. West on Friday.

Q. And that -- that conversation was -- or at least the basis of a late payment fee was discussed in twofold. One is to incent -- or disincent, I guess, late payments, right, to change customer behavior by imposing a penalty, and the other was to reflect -- I think Mr. West said something along the lines of -- just give me one second here -- the cost could pass through receivables maybe?

A. That's correct.

Q. The cost of financing those? So can you tell me what the Company does with past-due receivables?

Let me ask this.

A. (Indiscernible.)

Q. What does the Company do generally with receivables -- accounts receivables?

A. Right. So we factor with AEP credits, I think as we discussed at great length, the last rate case with the then-vice chair, but, yes, three factors. (Indiscernible) receivables with AC credit, and then there is a finance charge that comes back based on the time value of money. And there's a collection experience and bad debt that is all rolled in there.

So to the extent a customer does not pay on time, there is a cost to the Company of -- it flows through the financing, right? So you have -- you receive less of your receivables back. That's the cost.

So I think that's what Company Witness West was referring to when he was saying that the late payment charge or late fees are helping to cover the -- you know, essentially the increase in cost of late payments or bad debt collection through the factoring.

Q. Is that cost already accounted for in the proposed revenue requirement, absent the late payment fee revenues?

A. No. They're both in there. You have the total cost of factoring is in there, and you also have the total cost -- the total revenues received in late payment fees.

So I think what he said, there's over $4 million in late payment fees in the test year. So if you remove those, theoretically -- you know, if we can't charge a late fee going forward to cover that cost, the cost of service here in the revenue requirement would need to go up by 4 million.

Q. Yeah, and the question I have is is the cost of the late payment fee reflective of the actual costs incurred by the Company? Let me ask it differently.

What's the support for the amount proposed in the tariffs for the late payment fee, and how does it relate to the cost of account receivables?

A. I would need to look, but, offhand, I am not sure if the amount of late fees in the test year is equal to the amount of bad debt and higher financing charges for the time value of money on the late payments. I'm pretty sure we could give that to you

in a posthearing data request if you so wished.

Q. Hopefully this will be an easy one. Have you seen the chart on Mr. West's rebuttal? I think it's his third page on the rebuttal or his Table R3. I'm pretty sure it's his Table R3 in my scribbled-down notes. That he discusses the amortization of excess unprotected -- excess ADIT on a revenue requirement basis and then on a -- some other type of basis. I'm not quite sure how to refer to the other type of basis.

A. (Indiscernible) R3.

Q. Yeah. So let me just ask. There are two amounts -- for the Company's proposal, there are two amounts of excess. Those two charts, would you agree, or that table, the two things laid out in it represent the exact same transaction? Would you agree with that?

A. Yes, Your Honor. The top part of that table is actual ADFIT dollars as they sit on the balance sheet. And so, as you amortize them, they have an impact on income. And then to take that from the income to what will be a revenue requirement you gross up for state and federal taxes.

So that's the difference going from an ADFIT figure to a revenue number. So to offset $65

million in revenue, you amortize the $48 million of ADFIT.

Q. That's what I wanted to -- I appreciate -- that's very simple, and this is going to be a very good place in the record to reference at some point in the order, I think, that the -- there's a $48 million number -- without me looking it up -- is that right, on the top part of the chart?

A. $48,345,038.

Q. And we want to talk apples to apples. You've heard of the -- and it was the amount previously -- earlier this year, but that is apples to apples to that $113 million amount of the excess ADIT, right? That was the balance earlier this year of the unprotected excess ADIT?

A. Yeah, I believe so. If it was talking in terms of ADFIT, yes.

Q. Yeah, and so when we're talking about that, the actual revenue -- just so I'm clear, the revenue requirement impact of ADIT is effectively grossed up. So it has a greater impact on a revenue requirement than it does on a books basis. Is that fair?

A. Yeah. Essentially, if you're trying to offset $1 of a revenue requirement, you amortize

70-ish cents of ADFIT.

Q. Perfect. Thank you.

I wanted to ask -- and I think it's just -- I think it's a mismatch in words, Mr. Vaughan, but I wanted to make sure that we're on the same page about something that I understand is yours and the Company's position.

Earlier you were talking about -- let me find this here. I apologize. It will come to me in a minute. Oh, Mr. Fitzgerald, I believe, was asking you a question about the kilowatt hours put back onto the grid from a net-metering customer insofar as they are producing in excess of demand. Do you remember talking to him about that?

A. We talked at great length about that, yes.

Q. And do you remember you saying something along the lines of -- that -- that kilowatt hour will be going to serve someone else, effectively netting the Company's demand -- or the Company's load?

A. That's right. If you look at the Company from a billing standpoint, right, say the total load-serving entity that is Kentucky Power, right, its entire distribution load is lower at that point when the excess energy is pushed onto the grid.

Q. And I understand it that way too, because I look at it as a behind the meter -- as if you get one bill, and you have one meter from PJM, right?

Let me ask you about it. For some reason, when you were talking about individual customers who just so happened to be generating customers, right, somebody who may have been a net meterer or may be a new NMS customer or have some sort of behind-the-meter generation, you were discussing earlier that that person's load is effectively the exact same as a residential -- as another homogeneous customer, right?

A. Yeah, what I was saying is their load shape is generally the same across -- you know, a residential customer is a residential customer is a residential customer.

So if you look at the underlying load, the shapes are exactly the same across populations, the difference being -- the only difference being is when the customer's net-metered generation injects generation there and nets in the meter to reduce that load shape.

You can lay them over top of each other, and the only difference is, you know, let's say you had two meters on it, and you take -- you take the solar

generation meter off. The other one lays right over top of the class average load shape. It's exactly the same. So when you add it back, there's that dip in the middle.

If you look at those graphs in my rebuttal testimony towards the end, you can see that. So, yeah, the net load, when it's generating, is different, but the underlying load shape is the same.

Q. Yeah, but why do you care about the underlying load shape?

A. For the basis of charging that customer a retail rate. If their load is the same but for this other thing, if I compensate you, the Company provides the compensation rate or avoided cost rate that accounts for all the value of that difference, then the retail rate should be the same across the customer class.

Q. Right. But we're talking about two different things here, right? We're talking about producing your electricity behind the meter to the extent you have demand, which is one side, and then we have production in excess demand on the other side, right? Those are distinct -- those are distinct issues, correct?

A. The whole thing shows up as a load reduction either way, whether it's you reducing your load or reducing the Company's overall distribution load.

Q. Yeah. And I tend to agree that the overall effect is the same, but my question is, if -- most of these customers don't have two meters, right? They just have one meter.

So let's just say hypothetically somebody put a system on their home, right, a solar system on their home and never put energy back onto the system, right? They only reduce -- they only produce electricity up to their own demand in any given hour or any given one-minute increment, right? You all, as a company on your meter, wouldn't see a load profile materially different than the class average, right?

A. The underlying load profile would not be different but for the generation. So the point of that whole discussion is whether the appropriate rate for charging the net load from NMS II customers, whether that residential rate is appropriate or not.

And my testimony is because they are the same load at the same basis for whatever net billing kilowatt hours they have in a month under an NMS II,

the residential rate is appropriate.

So then under your scenario where they never -- they never produce anything in excess, they are still netting that load, and they're avoiding that full retail rate in that netting period.

Q. They certainly are, but what I'm asking is, insofar as they are avoiding being the average class producer, right, or the average class customer, if you continue to treat all those people identically, they're all going to be on that low end of the class average, right? They're all going to have a lower demand than the class average.

A. Here's the thing, though. If you look at the net metering and NMS II, you have to look at in two pieces. Do you have the correct rate for charging billable kilowatt hours, which my position is we absolutely do because the underlying load is the same. Then you have to look at what is the value, the financial dollar denominated value of the avoided cost from that customer producing energy from its system.

And, like I said, it's between 3 and 4 cents a kilowatt hour for all of that energy, whether it's netting behind the meter or they're pushing it out on the grid.

So they're getting far more than that avoided cost of energy is worth when they're netting behind their meter, and then if they're getting compensated for the extra when it goes over, you know, their load in that billing period.

Q. But let me ask it this way: In what other tariffs does the Company look at what the customer's ultimate usage is versus what their demanded load is from the Company in determining what homogeneous group they should be placed in for cost-of-service purposes?

A. Before I answer that, one more point on your last question. The issue is, as I showed in my rebuttal testimony, the load reduction from the net metering generation is worth less than the loss of billing kilowatt hours -- they don't offset one another. So it actually adds costs from a marginal standpoint.

The reduction in fixed cost recovery from the lost billing units is greater than the avoided cost of that customer netting its energy supply behind the meter.

And then to answer this -- this question you just asked, every general service rate we have for this TOD (indiscernible), all of those rates are

included in one overall class load shape -- I mean, load research study when we do that.

So you look at very broad groups of homogeneous customers for doing these statistical analyses, and then you use that to allocate total revenue requirements for the larger major classes, and then you divide up how you recover that total class revenue requirement in actual rate design, right?

So I didn't run a separate load research study for just general service athletic fields or for GS time of day. You do it for GS, and then you piece out the various parts of it when you're designing rates. So it's very consistent with how we design rates and always have.

Q. And I appreciate the insight into the cost-of-service calculations, but I have a very specific question. What other -- in doing cost of service in Kentucky or any other AEP affiliate, when does the Company look at what the actual usage is versus what the demand and load from the Company is?

A. Say again.

Q. You keep saying that the load is the same for a generator, that, heck, even if they don't push any energy back onto the grid, that they just generate

enough to meet their demand in certain hours, right, that that person -- that that person is homogeneous to all the residential customers because their load is exactly the same.

But you would agree that, as it relates to the meter in which the Company serves that customer, that is not the same, because you said earlier but for that netting they'd be the same, but for that netting. You know, but for a lot of things everything would be the same.

So I'm asking specifically to -- yes, I get that that customer may be using identically to what another residential customer uses as an in-use, right, the total number of kilowatt hours may be used between two identical customers, but if one of them is generating behind the meter, never exporting, but generating behind the meter to meet their own demand at certain times, as it relates to the Company, in what other venue in cost of service and in AEP's territory here in Kentucky or other states does it look at the end usage of the customer in totality or terms of demand instead of the load or demand at the meter?

A. Sorry, Your Honor. Your question is really confusing me because the end-use energy -- the

billing energy is the same as what the other thing you're describing, that the usage at the meter there.

Again, what I'm trying to differentiate here is there are two pieces to NMS II, right? You're trying to determine what is -- what is the appropriate rate to charge any billable kilowatt hours, and my testimony about the load shape is, look, that customer is the same. Take the solar system off their house, they're a residential customer like everybody else.

So the residential rate for any billing kilowatt hours is appropriate. Now you add that -- you add that solar system back on there, and again, you're absolutely correct, you're netting there at the meter instantaneously, and as long as you're valuing -- from a billing standpoint you're valuing that generation correctly, you get to the right spot without having to divide them out into some other (indiscernible) that is relevant.

They're getting the full retail rate when they actually net in the netting period, and then they are -- which, again, I think is generous, right? There's distribution, transmission, and other fixed costs in there that they use every day, and then you

have the avoided cost rate for the excess generation.

You really have to look at it in two pieces, and that's my answer there. The load shape discussion is purely for what is the appropriate rate to charge billable kilowatt hours.

Q. Let me ask if this is fair, then. They are a residential customer because it's a home regardless of their usage pattern. Is that your testimony?

A. Absolutely, they're homogeneous to the rest of the customers. Just like an industrial customer that has some small cogen behind the meter, it's homogeneous to other industrial customers, and they get billed the same as everybody else.

Q. Okay. So, like I said, I'm really trying to mark things off here.

Let me ask a follow-up on accounts receivable. I think on your page 6 of your rebuttal, you say that if rate basis is used to calculate a revenue requirement, then the accounts receivable financing should be removed from the capital structure and the resulting weighted average cost of capital calculation.

Could you tell me why?

A. It's kind of a two-parter there. If you do

decide to go to rate base, which it's fine, again, as long as you include all of the properly financed electric utility service amounts.

So if you do make that jump to rate base, and then my testimony is if you impute a lead lag study on the Company where you're essentially reducing rate base for AR financing, you know, in a cash rate capital-type calculation, that you then take in credit for that, those funds. That amount you reduced the Company's rate base for it, you can't then also reduce the cost of money as including it as some form of capitalization.

So it's like ADFIT. Some jurisdictions across the U.S. will include it as a rate base credit, some will include it in the overall cost of capital as, you know, cost-free capital. You can only recognize the benefit in one place. Same concept.

Q. Okay. I'll save the confidential stuff for last.

Let's just real quickly -- do you mind to go to your direct testimony, Mr. Vaughan? And I'm going to ask you to give me the Cliff notes part if you can because, I'll just be honest, I read the direct on the net-metering proposal, and I'm not exactly clear. So I have a couple clarifying

questions. So let me know when you're on page 24.
A. I'm there.
Q. Okay. So you're proposing two time-of-use periods, right? 8:00 a.m. to 6:00 p.m. and then 6:00 p.m. to 8:00 a.m., right?
A. Yes, Your Honor.
Q. Okay. And there are these two terms that you use, net negative energy and net positive billing energy and demand.
A. Yes.
Q. Okay. So net negative energy is when the customer produces more than their demand and exports, right?
A. Yes, in the total accumulated over the month and the total netting period. So, yeah, you can -- the net negative energy can be discussed in the same way as we said, like excess generation or exports, but again, it's that the accumulation of those figures within each netting period across the whole billing cycle.

So if the customer had net exports or net negative energy, some throughout the billing period, they would then be compensated for that accumulated net negative energy at the avoided cost rate.

Q. Okay. So first question I have is, under

your proposal, if a customer has a net-metering system and produces only enough energy to offset their demand in any given hour, right? Let's just make up something.

Let's just say that your net-metering tariff is fuel -- I know that's not the right term -- but fuel neutral. It's not just solar. Right? Could be anything. And the customer produces enough electricity in every hour of the day to meet its own demand, right, and never exports any energy. Would the customer's bill at the end of the month be the customer charge?

A. Yes. If the customer was able to offset all of its hourly generation within those netting periods, either netting period, the one at night, with self-generation so that there are no billable kilowatt hours, it would be the basic service charge.

Q. Because it effectively took no kilowatt hours from the Company. That's a fair way to think about it, right?

A. If it produced zero billing kilowatt hours, you're correct. And they will avoid paying for any of the infrastructure in that scenario.

Q. So what you're proposing is -- let me go to

the next thing. Page 25, I see that you tried to do some average calculation here with 1240, right?

And you just said that (Reading) The Company would expect a typical residential customer having a typical solar net-metering installation to have approximately 639 kilowatt hours of billing energy and produce 783 kilowatt hours of excess generation in a billing period.

Do you see that?

A. Yes, Your Honor.

Q. Okay. Is 783 the NNE in that period?

A. The answer is I revised all these numbers for rebuttal because of my initial, I guess, 4-82 where we had the -- some commercial systems initially included in the residential total because they had residential customers' names on the application rather than the commercial account, but essentially, yes.

If you're -- the difference between what is netted in the netting period of the customer's 1,240 average kilowatt hours and what is produced by the system is that net negative energy where the average -- (indiscernible)

Q. What is the 639?

A. So that's -- so right. When the solar system

stops producing energy late in the afternoon, and subsequently when the sun goes down, and customers are using the Company's system, you're accumulating billable kilowatt hours in that second netting period.

So that 639 is what the portion of net load in that second billing netting period under NMS II. So it's the accumulation of billing kilowatt hours. So in this example the customer is going to on its bill pay for 639 kilowatt hours basic service charge, and then it's going to receive a credit at the avoided cost rate for all of the -- that negative energy.

Q. Yeah. And that's what I want to make sure. I think this will help me understand it better. Under the old net metering, we'll call it, right, where it's a credit between the two, it would -- this customer in this billing period -- this average customer, whatever -- would have effectively carried forward a credit of -- do this on the fly -- 144 kilowatt hours onto the next month, right?

A. Yes. So they would have wiped out all their billable kilowatt hours even though they used them, but there would still be more left over.

And just to clarify something, I think Mr. Fitzgerald and I were talking past each other.

So if the customer -- like in this example, if the calculation resulted in a net bill credit in a month, so they produce enough energy that it netted their rate billings including the service charge to a negative amount, went to zero, and there's $10 left over of credit, that $10 rolls to the next month for use in that month.

So what I was trying to say is that you're figuring it out each month, the rate credit and the rate billings, but if there is a net negative, it does roll over per the applicable law.

Q. Okay. That is -- that is very helpful because I think I've read that 25 times. So -- so let me just ask as the second question to follow up with that is: How did the Company -- how did you come up with the -- in your proposed kilowatt hour compensation rate, you weighted for on- and off-peak LMP, but that amount applies to both on- and off-peak periods, right?

I say on- and off-peak periods. You know what I mean, right? The 8:00 to 6:00 and then again from the 6:00 to 8:00. That same kilowatt hour amount applies to both periods; is that right?

A. So it's highly unlikely you're going to see any net negative energy in that second billing

period because the solar generation curve has fallen off, right? Customers are picking up their normal household activities in the evenings. Solar generation really starts to fall off there in the middle, late afternoon and into the evening. So just based on the generation shape, you're going to have those -- those credits.

And again, that's why we designed the netting periods the way we did, right? So you have the majority of the solar within the netting period that's actually producing energy, and, as such, we've weighted that compensation rate, the avoided cost rate, to track with that.

Q. Yeah. But aren't you discounting it, then, since the majority -- if the Company expects the entirety, effectively, right, the almost entirety of the net generation to be produced between 8:00 and 6:00, and then it discounts it to provide -- I think it was -- 2/7 of the energy, assuming that is not actually the LMP at the time different than that amount, then how do you take into account that the majority or if not all of the energy being provided is on peak energy to the Company?

A. The 2/7 are weekends, Your Honor. They are not on peak.

Q. Okay. So --
A. (Indiscernible).
Q. (Indiscernible). And, literally, you're just saying it's reflective of the weekend then?
A. Yeah. Right? The 5/7 is your weekday on-peak hours in total. So you're taking into account, yeah, the sun is still shining on what we would consider an on-peak hour, but from an energy market standpoint, the weekend draw peak and the prices track with off-peak, you know, during-the-week prices.
Q. So explain what data set you used as described as "on peak"?
A. I looked at the actual hourly LMPs from the test year, and so -- I'd have to go back and calculate it, but your weekday on-peak hours that would match up with what the hours of sunshine and producing.
Q. So did you do weekday 8:00 to 6:00 average LMP 50-minute increments 8:00 to 6:00 p.m. for a certain time?
A. It sounds about right. You're trying to get to a number of hours in the year, which I think is what the calculation did, because then we used forward pricing based on the -- for the LMPs for our

avoided cost rate to try and track when the rates would be in rate, and those were very close to what we've been experiencing on a historical basis.

So, yeah, the 2/7 is accounting for weekends, right? I totally agree the sun is not shining or producing energy in the evening and night off-peak hours.

Q. Okay. And then, as it relates to capacity, how did you calculate on a production basis? Because I don't want to get into, not yet, distribution transmission capacity consideration, but on a production basis how did you calculate an avoided capacity rate?

A. So what we did there is we took the solar shape, and we -- you know, month to month, you lay it over when the PJM 5-CP generally occur, right, because it's a load reducer; it's not a resource out there facing the market.

So you look at how does the solar load shape reduce the 5-C -- how does it affect -- the 5-CP hours in PJM? So you come up with, if you have a 1-megawatt resource, you weight it towards the 5-CP contribution. All right? Well, it's actually 500-kw resource based on when those hours occurred.

You do that for a number of years, as I did,

and that shows up in AEV Exhibit 3 of my direct testimony and my work papers. Has to do with that, call it the 500-kW.

You have to get the peak reduction value of it first, and then you apply it to what you think your potential avoided cost is, and in this case it would be -- if we lower the 5-CP, the Company will potentially make an additional sale of length in the RPM market so we avoided -- we priced it at that (indiscernible) tariff.

Q. I'm getting some sort of feedback.

So let me ask, why is that the appropriate capacity value when the Company's embedded megawatt production value is significantly more?

A. Because you're not avoiding those. You're looking at it from an incremental or decremental standpoint. There's no avoiding what we already have. There's avoiding something in the future, or there's adding in more revenues from an increase in market sales.

Q. Yeah. So on that, the Company is going to be capacity-deficient in two years; is that right?

A. Yes. It's my understanding we are capacity-deficient of part of '22-'23 when the Rockport EPA goes away.

Q. So I guess I'll just say -- I'll make a comment and see if you can respond with an answer. I don't understand how using -- use the BRA clearing prices from a previous delivery year or for the next delivery year, is that the capacity rate you used?

A. I used $100 a megawatt day because the previous delivery year was 70, and the one above it was -- the next one was like 140, and the current was 100. So it's actually right in the middle and seemed very reasonable for the pricing points that we have currently.

And so just to, you know, kind of touch on what you just addressed there, when the Company does go short in '22-'23, it will purchase length through the Company's FRR plan from its affiliates at the avoided cost of -- or at what the companies would have made sales at in the RPM had been, had they not had to cover that length at Kentucky Power. So it will be the BRA price then as well.

But whatever that is, whenever the option clears next year sometime now. And, you know, then after that, you know, the Company has an IRP case pending and I assume will make some sort of proposal for how we fix that capacity short in a more long-term or medium-term basis than just purchasing

its needs from the other companies in the plan. So --

Q. And that would be an embedded cost, right?

A. No, no. You mean -- you mean how will we decide to -- however we decide and the Commission approves that we -- that we --

Q. The future capacity deficit.

A. The future capacity deficit, right. And that is more like what you're looking at in cogen/SPP, right? And, again, you're not avoiding that through adding a DG system. You know, like 500 kW is not avoiding 140-megawatt purchase, right? You're avoiding some piece of that.

If you're looking at a true -- it's a more long-term calculation like that, it would be what we have in cogen/SPP for like a PURPA rate where it's like, again, my hypothetical CP or some sort of dispatchable resource.

Q. So do you-all -- when you-all are doing DSM programs, do you-all ignore incremental 1.5-megawatt, you know, capacity reductions as -- at a -- some sort of reduced value because it's only incremental instead of -- you know, instead avoiding entire purchases or capacity additions?

A. I do. You can see that in the DRS --

proposed DRS rate schedule here when we're trying to peak shape customers. We look at, right, what are our circumstances right now? Capacity is sufficient. If I can shave a megawatt of load through DRS, my incremental revenue from that is making the Company a little bit longer and making another sale into the market and avoiding some other fixed cost of transmission, which I've also included in both DRS and in the avoided cost rate in NMS II.

You can use a variety of price signals when you're doing economic analysis on a DSM measure or EE program. It's kind of whatever -- you know, whatever you're looking at, but no, you're not -- again, I totally agree you're not going to avoid some sort of 400- or 100-megawatt increment of capacity with EE measure in full or, you know, rooftop solar. And, again, neither are dispatchable.

You have to take all those things into account when you're looking at how you're pricing something on the margin.

Q. I guess what I would ask is, based on your load duration -- I guess that's what you looked at -- based on your load duration study on PP, right, or distributed generation, I would assume that you

would ascribe some sort of in excess of 50 percent capacity value to it because it's coincident with PJM's 5-CP, which drives the FRR plan, right?

A. Yes, exactly. We looked at how it affects 5-CP hours over -- I think I did three years, and then get a three-year average of what the average load reduction would be, and you catch that variability in the hours of 15 through 18 that generally happen in PJM for the 5-CP summer peaks, and then 12-CP load reduction for, you know, reducing load-based transmission costs.

Q. And then based on that coincident value, you ascribed the capacity value of 100 megawatts or $100 a megawatt a day. Excuse me.

A. Yeah. The generation portion was that, and then the transmission portion was the, you know, cost of transmission in the zone.

Q. Okay. I have one more question with that section if you'll bear with me.

Are you aware of the minimum size study used in cost-of-service studies for a distribution plant?

A. Minimum system?

Q. Minimum system. Excuse me.

A. I am aware of that. I provided a version of that in Staff discovery.

Q. Can you just very quickly, what's the basis of the minimum system study?

A. The minimum is kind of a misnomer. I generally look at it as a typical, right, because you don't -- and again, I'll split hairs here because you don't -- you don't take the system down to the very smallest you can use for a customer, you take it down to the lowest economically common infrastructure you put in, you know, where -- where the 825 -- again, totally making up numbers here. Mr. Phillips will now back me up that you can do any of these things.

But you can put a 20-foot pole and a 2-kV transformer on customer A's house, but through purchasing and just normal operations, we know that a 35-foot pole and a 7-kV transformer is the least cost for everybody to generally serve needs.

A true minimum system study would just look at what would happen if you designed the system based on (indiscernible) what your smallest possible is.

And what I did is that typical, so what is our smallest typical installation that we use for the various pieces of distribution equipment to serve customers in general, and the theory behind the whole study is that everything up to the typical

level of equipment is completely fixed in nature and does not vary by anything other than the number of customers on your system, which makes sense when you're looking at, like, radial distribution service, right?

If there weren't customers out there two miles down this road, you wouldn't have run conductor and poles and transformers there to serve them. And then everything above -- size above that typical installation is demand-based because, in theory, there was a -- you know, if 7 kV is your typical installation on this circuit, but you have 10 kV or 20 kV on this other circuit, you did that because the demand on it required that.

So you're separating out the overall fixed costs into what is fixed by number of customers and what is varying by the demand on the system, the -- you know, kW demand.

Q. KW or kV. So --

A. Yeah.

Q. So let me ask -- and this is the -- something I don't know if anybody ever addressed directly as it relates to that.

We have in this case these marginal -- these marginal conversations, right, marginal costs in

conversations, and then embedded costs in conversations. And they're kind of fun for the three of us. They're intermingled together, right? So we've got to sort of -- where does it make most sense to do either, if either.

So when it comes to this discussion -- and I just want your perspective on it. When it comes to this discussion on avoided distribution cost, right, when the Company makes decisions -- rightfully -- right, wrong, doesn't matter -- I'm just saying makes the decisions, to your point, to have this -- I know you don't like the minimum system, but the minimum practical system, whatever it may be, does that -- but we're never going to go get a 2-kV transformer, we're just going to buy 5 kV because we got a
15 percent discount on both, right, or whatever it might be -- that -- would you agree that that creates again some sort of inherent -- that insofar as the Company is making a conscious decision to do something this way, right, and it may be good utility practice, whatever it may be, but because of those other decisions, that negates the ability, I'll even say, to determine avoided distribution cost when we're talking about things like

distributed generation.

Because the Company's always going to have a kV -- insofar as it's not higher, right, but lower -- that the smallest transformer the Company is going to put on a line is a 5-kV transformer because that's the smallest they carry, right, even if a distributed generation system reduces demand.

Does that create an inherent sort of complication with calculating those figures?

A. No, especially when you're looking at a winter-peaking utility like Kentucky Power. We would show it in the test year data, and all my analyses, that net-metering customers are contributing just like everyone else to the full distribution peak when it happens at 6:00 a.m. There's no sun up. It's dark and it's February, so their load is just in that -- that highest distribution hour like everyone else's, so no.

I mean, even if they do reduce every other month peak theoretically on the distribution system, you still have to size it to handle their peak load, which happens before the sun is up.

Q. Yeah, and I'm not asking specific to your proposal in this case. I'm just saying the distinction between the marginal costing and the

embedded cost-of-service studies, or even the practical effect of utility planning, does one -- let me ask you this way: Do costing studies drive expenses, or do the practical expenses and running of the utility drive cost-of-service studies?

A. Again?

Q. Would you agree that the cost-of-service study is just an attempt to put on paper, right, the interaction of the things that have already been done in the field or anticipated to be done in the utilities practice, right?

A. That's right. Mr. Phillips does not consult me to come up with rates before he -- he provides safe, reliable utility service. I am the back office nerd that then takes care of whatever needs to be done from a cost of service and rate design perspective.

Q. And with a marginal cost study, for instance, it's just putting on paper reflecting what the actual practice is going to be -- or what the practice has already been, right?

A. It depends, right? And when we look at the marginal cost-of-service analysis I did, especially with the basic service charge, I'm not proposing that we use that. I'm using that as an informative

guide to what you could potentially move that charge up to before you have to start considering larger items, you know, other issues within distribution and other cost of service as to whether you're going too high on that basic service charge or not.

But then if you're looking at something on a marginal basis like EDR load, whether that meets all the statutory rules, whether the Company should do a peak shaving program like the DRS, or whether you're compensating marginal injections into the distribution grid from a customer generator, those are all very valid uses of a marginal cost-of-service study and that they should be used. So the answer is (indiscernible).

Q. Yeah, I've found that here, doing this, it's always -- the utility world -- there's a lot of nuance, and it very much depends. And I can appreciate that.

A. All gray, yes.

Q. On the EV proposal, real quick, you stated on your direct in '19 that (Reading) The Company does not propose an extra basic service charge for customers that subscribe to the EV charging provision because the cost of the separate second meter for the customer is being offset by the

additional fixed-cost contributions from the on-peak and off-peak energy charges.

So it's a big record. I may have missed it. Where do you provide the cost-of-service support to indicate that's the case, that the savings from the use -- from the demand in energy offset the fixed-cost savings that the other customers would get from that person paying a meter charge?

A. It is in one of the many Staff discovery responses. We can provide that exact one, but I don't have it offhand.

But that's the theory. You're looking at it just like I did in Exhibit 9, that EDR load. You know, if you add this load, are you overcoming the marginal costs of adding it and producing positive fixed-cost contributions. So yes, it's somewhere in Staff discovery, and we'll provide that.

Q. Let me ask this question: Is there a disconnect -- that's the only word I know how to come up with. Is there a disconnect between the savings that you may -- would you agree that the savings from that are going to be demand-related for cost-of-service purposes?

A. (Indiscernible).

Q. What's that?

A. I'm sorry. What savings are you referring to?

Q. Well, so you said that the fixed-cost contributions -- let me get this right.

So (Reading) The Company does not propose an extra basic charge for customers who subscribe to the EV charging provision because the cost of the separate second meter for the customer is being offset by the additional fixed-cost contributions from on-peak and off-peak energy charges.

So what I'm asking is would you agree there's a disconnect between the cost of the meter -- which I assume you're, in the cost-of-service study, saying is customer-related costs -- and the fixed-cost savings for the on-peak/off-peak energy usage is production and demand, or demand-related?

A. So it's not really a cost reduction, right? You got to look at it as we are trying to have this -- think of it as you're incenting this customer to charge in the off peak, you know, and so you're adding off-peak billing kilowatt hours, and you're giving them this separate meter time-of-use rate so they don't have to put their entire life on time-of-use rate at their billing address.

So what I show in that Staff data request is

that their additional fixed-cost contribution from that rate, so everything above fuel, is enough to offset that customer's cost of the meter, the separate meter. Again, because that is customer-related, I totally agree. And then you provide incremental fixed-cost contributions.

So it's more of a -- I look at it more as there's -- the incremental revenues from adding that load is greater than the incremental cost of serving it.

Q. Yeah, but the revenues being allocated are being allocated in a cost-of-service study to production and transmission and distribution-related costs that are probably being allocated that are on a demand basis, right?

A. That would all stay within the class. So it's residential class revenue. That would stay in the class -- or general service, EV charging, general service class. You're not allocating revenue. The revenues stay within the class.

Q. But you're driving -- you're increasing customer-related costs for the entire class, right, because you're adding in additional --

A. To a lesser extent than you are adding revenue, yes.

Q. Okay. The other question about DRS, I just want to make sure that I understand what DRS is. Effectively, it's going to be the Company's own peak shaving program so as to reduce its demand -- its bill from PJM effectively, right?

That single meter, you're just attempting to do it behind the meter, reduce your own demand behind the meter so that your FRR plan is continually lower and lower effectively, right? That your demand for purposes of PJM's 5-CP is lower?

A. Yes, Your Honor. And kind of the impetus behind this is we have -- we've been doing this in special contracts in other jurisdictions, and, hopefully, we proposed it in Virginia -- I proposed it in Virginia. And, hopefully, it's approved here very shortly, but the thought here is, when we talk with industrial customers, they -- you know, shockingly, customers are weary of PJM rule changes in the demand-response market, right? They don't like being exposed to capacity performance, which became the only product for demand response starting last June.

It basically says, hey, if the system -- we get, you know, the scarcity on the system, we can

call your demand-side resources whenever we want, and if you don't respond, I'm going to hit you with a penalty up to $3,500 a megawatt hour, so that made a lot of people shaky, and we have some very large industrial loads in some other companies that were also very interruptible.

So we started doing this concept to address those. You have a customer that still provides the demand-response service, but we're taking them out of the market. We are exactly what you said, we're putting them behind our meter and taking them from the supply side of the equation, which always seems weird with demand resources, and putting them on the demand side, right?

But the difference is, though, that customer is going to have to interrupt when we call them when we think the 5-CPs and the 12-CPs are occurring so we can actually reduce load versus they may have sat there as a resource on a PJM program for years and never had to interrupt other than annual testing.

So it's a trade-off, right? The customer is avoiding risk of the RPM market or the capacity performance charges, but they are going to probably have to interrupt more under our peak shaving program than they would under a PJM program.

Q. Okay.

VICE CHAIRMAN CHANDLER: And, Chairman, I have, I think, two more short questions and then two -- a little longer ones. So after the short ones, would you like to take a break?

CHAIRMAN SCHMITT: You want to take a break now?

VICE CHAIRMAN CHANDLER: Let me ask these two short questions. If that's okay.

CHAIRMAN SCHMITT: Sure. Sure. Go ahead.

Q. There are two of them. The first is I seem to be confused. Mr. Blankenship? Blankenbaker? It's been a long week.

A. Blankenship.

Q. Blankenship, thank you, spoke and said that the meters -- the AMR meters, talking about the ones currently, were obsolete, I think is the word that keeps getting thrown out. But I heard something in your testimony I want to clarify. Are they fully depreciated?

A. To my knowledge, no, they are not, because I don't think we've updated depreciation rates in several rate cases.

Q. Okay. So if the Staff asks for a posthearing data request on the -- where the depreciation is on

those current meters, you can provide that? Maybe not you, the Company.

A. I think it's already in the record, but we can definitely point you to that. I think the net book value figure is in the record.

Q. Okay. I appreciate that.

The other very short question -- and I'm reading this from somebody else, so bear with me. Do you have your response to Staff DR 6-7 regarding the financing of those -- I believe those coal -- Mitchell coal purchases?

A. I do.

Q. Okay. In the test year does the Company finance the purchases through short-term debt?

A. Sorry. Bear with me. I'm rereading this. I'm sorry. Can you repeat your question now?

Q. Yeah. During the test year, did Kentucky Power finance the coal purchases through short-term debt -- with short-term debt?

A. 6-7 says that the Company uses its working capacity resources to pay for expenses from its operations as they are incurred. All capitalized items, including the Mitchell coal inventory, are financed based upon the Company's overall capital structure.

And then it goes on to explain why I adjusted -- or why we adjusted this Mitchell coal short-term debt to zero because of the Mitchell coal stock adjustment.

Q. So if there's a specific allocation -- there may or may not be -- but if there's a specific allocation to the way the Company finances that, you-all could provide that in a posthearing data request?

A. Can you ask that again? If there's a specific way we finance the coal stock?

Q. Yeah, that those costs are allocated when financing during a particular year or during the test year?

A. Allocated to one specific source of capital versus another? Is that what you're trying to distinguish?

Q. Yes.

A. Yeah, I (indiscernible), but I think we can.

Q. Your answer -- yeah, your answer, you would indicate that it's just part of overall financing, so we do everything at the WACC.

A. That's right. And the reason -- again, there's some history behind this adjustment in the way we've mechanically adjusted the cap structure

and the WACC through our filing schedules in Section 5 over time.

Two rate cases ago in 2014, where -- because we remove a lot of things from capitalization for base rates because they're earning a return elsewhere or they're nonutility or whatever, we reduced -- you know, we proportionately reduced all the components of capitalization.

And what happened is we actually ran short-term debt zero because it was -- the balance was so low when we removed everything, it went negative. So then, to get back to 100 percent, the function was to create fake equity and long-term debt. No one thought that was the right answer, so we agreed to zero out short-term debt.

And we have been doing that since to avoid that issue when you remove things from the capital structure and reduce all of the components, long-term debt, equity, AR financing, everything from a proportional basis. That's the reason behind that -- that tranche there, but yes, Your Honor, we can provide you with posthearing data request stating how we finance that item.

VICE CHAIRMAN CHANDLER: A little clarification real quick, Chairman, if you don't

mind.

Q. You just were talking about -- it just reminded me. I know there's just a portion of it.

Insofar as the Company doesn't earn what it expects in terms of its cost of service with the nonjurisdictional portions of its revenues, right, the -- we'll just say the nonjurisdictional portions of its revenue requirement.

A. (Indiscernible.)

Q. What's that?

A. Are you referring to like our small FERC jurisdiction and (indiscernible) reserves?

Q. Yeah. (Indiscernible). Insofar as the Company isn't earning its ROE as it relates to those, is that calculated in that, you know, GAAP earnings in a given year, or is that on a jurisdictional basis when the Company is talking about its inability to earn its ROE?

A. That's a total company ROE, but those customers are served via a formula rate with a true loss. So we're earning the ROE in a formula rate there.

Q. Right. But I guess what I'm asking is, insofar as it's -- you're underearning for that year, it may true up to the next year, but when

you're talking about currently a month in sort of numbers, is that taken into account?

A. No. It is what it is. So -- but, generally, that is earning the allowed return in the formula. So all other things being equal, it's probably pulling up the total Company ROE very miniscule, right, because it's 1 percent, 1 1/2 percent of the overall Kentucky Power.

VICE CHAIRMAN CHANDLER: Okay. Chairman, we can take a break. I appreciate it.

CHAIRMAN SCHMITT: All right. We'll now be in recess until ten minutes after 3:00.

(Recess from 2:57 p.m. to 3:18 p.m.)

CHAIRMAN SCHMITT: Okay. Are we all back on the record?

VICE CHAIRMAN CHANDLER: Can you hear us, Chairman?

MS. SACRE: I just got a note about a recorder stop. Let me make sure.

CHAIRMAN SCHMITT: There's a question about whether our system is properly working.

MS. SACRE: (Indiscernible). He'll come in here if it's not.

CHAIRMAN SCHMITT: We think we're okay. We're back on the record.

Ms. Gundermann, are you with us here this afternoon? Maybe not. Is someone present from the Attorney General's office? Do you think they can hear anything I'm saying?

MS. SACRE: That might be the problem.

MS. VINSEL: I'll go back and double-check with Jim.

CHAIRMAN SCHMITT: Vice Chairman, can you hear me?

MS. SACRE: They can't hear us.

CHAIRMAN SCHMITT: They can't hear a thing?

MS. SACRE: That's what I meant, this message I got.

MS. VINSEL: We need to go off the record for a few minutes.

CHAIRMAN SCHMITT: Well, I can't say anything, they can't hear me. Let's just go off the record. Maybe they can. They can't hear a word we're saying.

(Off-the-record discussion.)

CHAIRMAN SCHMITT: Are we back?

MS. SACRE: You're on the record, sir.

CHAIRMAN SCHMITT: Vice Chairman, can you hear?

VICE CHAIRMAN CHANDLER: We can.

CHAIRMAN SCHMITT: We've had a technological problem that caused us to -- caused a delay. Before we recommence your cross-examination, however, I would like to ask if Ms. Grundmann is present for Kmart.

MS. GRUNDMANN: Yes, Your Honor, I'm present.

CHAIRMAN SCHMITT: I know we spoke Friday. You, I thought, maybe had some concerns about your witness, and I was positive that we would get through with the Attorney General's witnesses today, and I wanted to ask if you had a problem -- if your witness had a problem being here tomorrow. And if that was the case, assuming the Attorney General's witnesses and KIUC's (indiscernible), I go ahead and let your witness go first today, believing that there probably will be little, if any, cross-examination.

MS. GRUNDMANN: Your Honor, my witness is flexible in terms of going late today, going tomorrow. Her schedule can accommodate whatever you desire.

CHAIRMAN SCHMITT: Well, I doubt there's any point in going late today because we've got ten witnesses left, and some of them, I'm sure, won't be as long as others, but I can't see us getting

through by 5:00 or 6:00.

MS. GRUNDMANN: I tend to agree, Your Honor, but she's fine with going tomorrow, but I appreciate you remembering my scheduling discussion last week.

CHAIRMAN SCHMITT: Well, I just wanted to make sure. I hate to see anybody have a witness problem, so anyway, that's okay. Maybe today, maybe tomorrow.

Ms. Blend? Ms. Blend?

MS. BLEND: Yes, Your Honor.

CHAIRMAN SCHMITT: In checking with our people here, it would appear as follows: That none of the Kentucky Power witnesses except Mr. Mattison will be the subject of any additional questioning, and I think one or more of the commissioners would like to speak with Mr. Mattison after the intervenors' witnesses have testified.

So if he can be available by video, all of your other witnesses can be excused. And I'm sorry that you had to have them there today, but we just didn't know, and so -- but, anyway, I wanted to let you know now.

MS. BLEND: Thank you, Your Honor. We appreciate that. We'll make sure that the witnesses know, and Mr. Mattison will be available tomorrow

after cross-examination and questioning of the intervenor witnesses has concluded.

CHAIRMAN SCHMITT: All right. Thank you.

At this time, Vice Chairman, are you ready to complete your cross-examination?

VICE CHAIRMAN CHANDLER: Yes. Thanks, Chairman.

Q. Mr. Vaughan, you can hear me okay?

A. I can. And before you ask your next question, could I provide you some references from our last conversation?

Q. Sure, but before we do that, can I ask you another question?

Can you provide additional color in a posthearing data request to your basis and assumptions for KPSC 4-72? I think it's Attachment 1, which is, I think, probably one of the things you're going to refer me to, which is the calculation of your EV information; is that right?

A. Yes. You one-up referenced me there. I was going to reference you to that.

Q. Okay. So KPSC 4-72, all I have is a Excel with a couple of lines that just have one- or two-word descriptions to them, and there's no narrative in the DR response.

So, if we asked for the assumptions and the calculations and the assumptions for the calculations, you'd be able to provide more color around your calculation?

A. Yes, Your Honor. There was a lot of data requests attached to that, so yeah.

Q. Okay. No. Sorry. Go ahead.

A. On the net book value of the meters, going to refer you to AG KIUC 1-65. And for -- yeah, 1-65, and then the preliminary depreciation analysis was AG KIUC 1-61.

Q. And let me ask that 1-65. I know that Staff had said something to me in the interim about that. Does it have in it what the assumed -- what the -- what curve they're using, what depreciable life that the current meters are being depreciated over? Or does it just have the net book value remaining of the meters in that account?

A. I think the meter account -- the life being assumed for the meter account is what you'll find in 1-61, the number of years used.

Q. Okay. And the actual net book value would be in 1-65?

A. That's right.

Q. Correct? Perfect.

A. Yeah.
Q. Okay. Can I get Staff to bring up the Company's response to Staff's 7-2? That's the wrong -- the wrong document. There we go. Okay.
And have you seen this document before, Mr. Vaughan?
A. Yes. I prepared it.
Q. Okay. And this is a distribution, or at least a data set, indicating the bills of all the Kentucky Power's residential customers for a certain time period, right? I think it's April of '19 until now. Is that right?
A. Yes, Your Honor, being the test year through our last current load billing information from September, yes.
Q. So the first question I'm going to ask in the posthearing data request is to run this with consistent X axis. Do you see that? I think that's the right axis. I didn't do very well in high school math, but I think that the distribution at the bottom runs in 100-kilowatt hour increments, and then beginning at 2000 runs in 500-kilowatt hour increments. Do you see that?
A. Yes.
Q. Okay. And you see how that kind of -- I'll

say it this way -- messes up how pretty the bell curve can be or how pretty the figure is?

A. Because there's a lot of bills in those ones, but, yeah --

Q. Yeah. It effectively makes it look like it's real noisy, but, ultimately, it's that the data set prior to it on that axis is only 100-kilowatt hour increments, and that one is all of a sudden 500-kilowatt hour increments?

A. Yes. That's a programmatic report, so I will see if we can change those -- those increments. And if we can, we will provide that information.

Q. Okay. And even if it's, you know, instead of 100-kilowatt hour increments, if it's 125 or 150 to try to make the figure smaller, because, ultimately, you know, it's -- the left-hand side of it is always going to be zero, and then to the right it's going to be whatever the highest number is, but I know the tail is going to always probably go for a while when you get over 500-kilowatt hours. So we're mindful of that.

So the average usage is something like, for residential Kentucky Power customers, is 1,239 hour -- 1,239-kilowatt hours a month, correct?

A. I think rounded up, it was 1,240 on the

button for the test year is what we've been using.

Q. Okay. All right. And in last case it was something like -- I remember it was around that same area, 1,213 --

A. (Indiscernible).

Q. Yeah. So the highest number of bills, ignoring, you know, that weird 2,025 amount, the highest number of bills, the highest distribution of 100-kilowatt hour increments is -- well, let me see if it will let me zoom here. Bear with me. Is, I believe, 800- to 900-kilowatt hours a month. Do you see that?

A. Yeah. It's (indiscernible) that number of bills. It's right there, just shy of a thousand kilowatt hours. That's right.

Q. And so the largest number of observation, the 100-kilowatt hour bills a month is right there in the 7 to 800, and then the average, though, is 1,240.

So I guess my question is, is the Company concerned by the vast number of observations significantly in excess of the Company's average residential bill usage?

A. Again, this is a product of the Company's service territory in the penetration of electric

heat. You get very large usage in cold weather months. Someone -- someone who could be -- you know, I think the -- I can't remember if it's Exhibit J, but the billing analysis, kind of typical billing analysis shows the shape of a residential customer's bill from month to month, and you can have someone that averages 700 kilowatt hours most months, and then uses 2,000, 3,000 kilowatt hours on a cold winter month.

And that's how you're getting that, that much higher average kilowatt-hour usage than what you'd see in the average bucket of bills. It's the extreme winter billings.

Q. So I've asked you about the EV, right, the tariff EV that you've proposed, the DRS. We've talked about load and DRs behind-the-meter generation. The only thing we haven't talked about is Order 2222 in correlation to all the different things that can happen.

So let me ask this: In the cumulation of all those things, at least we'll just say the EV and the DRS, we're talking about proposals where the Company is going out of their way making a proposal to ask customers to change their behavior where whatever costs the Company incurs in asking them to change

their behavior is more than offset by the customer's response. Is that fair?

A. I think that's typically fair. If we're going to incent someone to do something, compensate someone for a change in behavior, we want to make sure that all of the customers are at least no worse off for us doing that.

So, yeah, we want the cost-of-service benefit to be equal to or greater than the compensation paid to the customer.

Q. And I remember talking about avoided distribution costs, right, with you a minute ago with minimum system study, and you were discussing how it's your testimony that a lot of the costs on the distribution system in terms of sizing and demand-related costs are driven by the Company's winter peak and those demands that residential and commercial customers put on the Company when it comes to those winter peaks, right?

A. That's right. To the extent that it deviates from typical, which I would say is customer-based in cost assignment, that increments over that would be demand-related.

Q. All right. So I go back to the vast number of observations in excess of 2,000, 2,500 bills a

year. You know, we're talking about, let's say, in excess of 2,000, right? This is April to -- actually, I don't know what the end of this data set is -- April to August of this year, maybe September of this year?

A. September, yes.

Q. So September of this year. So April, so that's 12, 13, 16 months; is that right? 17 months?

A. Yes, that's right.

Q. We have observations in excess of 2,000-kilowatt hours a month. 10, 15 -- you know, coming up on 20,000 bills in Kentucky Power's territory in excess of 2,000-kilowatt hours a month, right?

A. Yes, absolutely. Look at December, January, February, and March. March can cause a lot of heating load too there in the early part. I mean, you look at the 2,000 to 3,000 segment, there are a lot of bills in there. Absolutely.

Q. Right. And that's what I was going to say. A lot of those are -- you know, there aren't -- it's not an insignificant number of bills when you start looking at 2,000-plus, particularly in the winter, right?

A. Absolutely.

Q. (Indiscernible). Go ahead.

A. I was just going to say, that's one of the impetuses for our -- the winter heating tail block we proposed.

Q. Well, like -- so about that. So like let's look at the -- I think it's the -- goodness gracious, is it really, the 2,500 to 3,000 kilowatt hours a month. And the one before that in January, February -- or December, January, and February, do you see that? Some of those are in 17 and 18,000 observations in those individual months.

Do you see that?

A. Yes, Your Honor.

Q. Okay. So of all the things that the Company can do in terms of proposals in front of the Commission, why propose merely a declining block schedule instead of something that addresses those particular customers who have that demand that drive those costs?

A. So here's the issue: Your heating load isn't -- isn't discretionary, right? I can't -- I don't really want to determine at what price a customer will choose to freeze, you know, rather than turn their heat to a comfortable level. That's definitely not what I'm doing here.

And, you know, the issue is with these large bills, these large -- these large usage categories. You see we have a lot of bills they throw based on the current rate design that has a large part of our fixed costs in the volumetric rate, it disproportionately impacts these electric heating customers.

And, again, cost causation, I agree, they contribute to distribution peaks, but they are not -- that incremental heating load -- and that's how we design the tail block, so that it's targeting the incremental usage over the same customers' nonheating average usage for the discount. That incremental heating usage is not contributing to like, say, a generation peak in the summertime, and it's not contributing to -- I don't know -- 8 of the 12 transmission CPs.

So we're trying to unburden the -- those disproportionately affected customers. You know, and, again, people say why don't you just put them on amp? Well, that just spreads that high bill out over more months. What we're trying to do here is actually lower that high bill on a cost causation basis, and the distribution portion of that rate is the same, whether it's in the first part of the

usage or in the winter tail block.

We're just moving around some of the generation costs there, you know, from a fixed-cost standpoint. It's my opinion these customers are contributing more than their fair share. So we're trying -- based on the rate design that's in existence, you know, between the kilowatt-hour charges and the percentage of revenue riders.

So we're trying to reduce that. And the same customers pay a little bit of that back over time because they are consuming, you know, first block kilowatt hours the rest of the year, but it is flattening out those really high winter bills that you see on these disproportionately large usage months, and it's trying to address the problem we have.

Q. Let's talk about that for a second. There's an observation January of 2020, there's 18,559 observations for customers who use between 2,000 and 2,500. Do you see that?

A. Yes, Your Honor.

Q. So let's just assume that those are weighted towards the bottom of that range, and that the average of those is 2,200, right? 2,200 kilowatt hours that month. That's a fair assumption, right?

We filled the bell curve. I mean, it's going to be pulled -- it's going to be pulled to the low range when we start talking about average, right? There's going to be less observations as you grow. We know that from data, correct?

A. Yeah. It could be somewhere in the middle, but yeah.

Q. Yeah. So let's just say 2,200. So what is the residential kilowatt-hour charge that's being proposed in this case, the first block?

A. I'll have to go to my schedule. I don't -- unfortunately, don't have everything offhand. Sorry. Bear with me here for a moment.

Q. That's okay. Don't forget to lean into the microphone just when you make comments, for the benefit of the court reporter.

A. The proposed residential block 1 rate for the whole year is 12.265 cents per kilowatt hour. The winter heating block is 6.265 cents per kilowatt hours.

Q. 6-point what? Excuse me.

A. 6.265.

Q. 6.265, and the ordinary is 12.265; is that right?

A. That's correct. There's a 6-cent difference.

Q. Okay. And the ordinary one, when does the winter block kick in? 1,100?

A. Yes.

Q. Okay.

A. In December, January, and February.

Q. So for, like, an ordinary -- so for the average customer in this block, those 18,000 observations, under the current, it's 2,200 times .12265. That would be a $269 volumetric bill, right? Does that sound right? It's the average times -- it's the average times 12.265, right?

A. Sure, yes. I'm not following along with the math here in my calculator.

Q. So we just said 2,200 kilowatt hours a month, right? We said that was a reasonable average of that 2,000 to 2,500 range, right?

So a person using 2,200 kilowatt hours a month in the winter under a nonblock schedule would pay 12.265 cents; is that correct?

A. No. If you didn't have a block rate, the rate would be lower.

Q. Rate would be lower. Do you know what it would be without the block rate?

A. Not offhand, but maybe to help out your -- under your example, the 2,200-kilowatt hour customer

in that month and the heating block kick in at 1,100, they're receiving a $66 bill reduction under my proposal of the tail block because of the block discount is 6 cents per kilowatt hour.

Q. Okay. Great. So $66 reduction on an approximately $260 original bill. Is that fair? 2,200 times 12.625?

A. Again, if you didn't have it, it would be -- it's circular. The 12.265 is only there because you have the reduction in the tail block.

Q. Okay. I guess my question is with some of the bills that we see, especially for people that use in excess of 2,000 kilowatt hours a month, right, the Commission gets 2,000-3,000-kilowatt-hour-a-month bills all the way up, right? Some of them 7, 8, $900.

When you get an $800 bill, and you can't afford an $800 bill, what good does a $500 bill, if you can't afford a $500 bill, do you?

A. I mean, it's $300 less. I mean, we're trying to take steps towards this. And, again, I'll piggyback on what Company Witness West discussed. You know, maybe with the AMI infrastructure this customer gets 3 or 4 days into the billing cycle and gets a high bill alert, and they can maybe make

their home less warm and cut down a little bit on that.

So, I mean, it's --

Q. Is the heating load discretionary or nondiscretionary?

A. In my opinion it's nondiscretionary. But, again, you know, I don't know what a typical customer, heating customer, is willing to do, you know, if they have more information or not. And, you know, again, gradualism here. We can't just take that $800 bill down to a hundred. There's cost impacts on that.

In this proposal, the winter heating block, if you look in Exhibit AEV1, which is the rate design for all the tariffs, but if you look at the residential line, essentially it's providing a $14.6 million discount to heating customers during the heating months, and that's being recovered partially, you know, from those same customers throughout the other months.

So you're levelizing a bunch, but you're lowering -- you're absolutely lowering those winter bills.

Q. And I guess my question is what is the Company going to do or what -- the Company's other

proposals is not to charge a different amount necessarily, right, and assume that people can't change their behavior. That's not your proposal for DSR; it's not your proposal for EV.

It's to offer them an incentive to do something different, right? To change their behavior. Here you're proposing that they won't change their behavior; you're making the rate less.

So I'm asking in terms of DSM or other options that the Company has at its discretion, what can the Company do to help people use less electricity in these extreme situations?

A. Just to be clear, Your Honor, my testimony is that this winter heating block discount is based on cost causation because of the disproportionate fixed-cost collection in the winter months and these high bills because of the underlying rate structure being too volumetric.

You know, we don't have these issues in a class like IGS or GS where you have more cost-of-service base rates that have demand charges, have kilowatt-hour rates, and then a service charge.

So that's the reason why we're doing this differently than we are looking at DRS or the EV rate. You know, these customer -- again, we're

coming at it just from a different direction.

To answer the second part of your question there, I don't have a solution, as I sit here today, for how I can help these customers heat their homes more efficiently. You know, I just don't have one for you.

Q. Would you agree that these extreme usage patterns in the winter do drive additional costs for the customers, for customers as a whole? Distribution expenses, for instance?

A. Yeah. Again, I'll agree on a distribution basis that it's sized to meet our peak load. That happens in the winter. Again, when you look at retail rates has distribution, generation, and transmission in it.

And again, if you go through the cost -- not the cost of service -- if you go through the rate design, kind of the distribution portion of that is the same whether it's in the -- recovering full distribution costs in that winter heating block, the 6.265 cents there, it's trying to lessen, you know, some of the cost contribution to those generation and transmission fixed costs that they're overpaying for, in my opinion.

Because, again, that heating load does not --

it's not there to power a 5-CP. It's not there for probably 8 of the 12, maybe 7, 8 of the 12 -- 12-CPs. Again, you got to look at all three cost-causing peaks.

But I absolutely agree, they are the reason that the distribution system is sized the way it is. That is our largest peak.

Q. Bear with me just for one second, Mr. Vaughan. I'm checking all my notes here.

Can I ask, then, with regard to -- I believe your testimony talks about the benefit from the Company's perspective of the declining block rate for lower-income customers. Do you remember that?

A. Yes.

Q. And it's the Company's position that this declining block schedule is a benefit to lower-income customers. And would you agree the Company's basis of that is the usage for LIHEAP customers?

A. It is. Those are the customers that I have direct insight into from a billing standpoint where I can flag those as these are the billing accounts for LIHEAP, and that, you know, versus any other economic measure of low income. Like that's the consistent thing I can see when we create a billing

system.

And that same pattern holds true in the Company's other Appalachian jurisdictions. You see the exact same pattern with electric heating and low income in Virginia and in West Virginia.

Q. Okay. And then you were asked in Staff 7-1 on this particular issue, right? The correlation between income and usage, correct?

A. I was asked to do a great many things in Staff 7-1.

Q. Well, and with all due respect, very little was done, so that's why I'm asking about it. So it's your position that the LIHEAP customers are effectively representative of lower-income customers as a whole for the Kentucky Power territory, right?

A. I'd say they're representative, yes.

Q. Okay. But when asked to actually compare the Company's data to, for instance, income information on a census basis, you were unable to.

A. Well, again, as the Company's response talks about, what was asked of the Company would have taken about -- oh, gosh, I can't remember -- many weeks to complete from a manual entry standpoint, and I'll be honest with you, I couldn't find the income data on the census website for my own census

track. So it was a bit of a struggle there.

Q. Okay. So instead of clarifying, for instance -- did you go to the website that was provided where it stated that you could put information in 10,000 observations at a time?

A. Many of us did, yes.

Q. Okay. But I just want to make clear, and it's really understanding this, is the Company's conclusion that lower-income customers use more electricity based exclusively in this case, right, the evidence in this case based exclusively off of the LIHEAP data?

A. Yes. My testimony is that our LIHEAP comparison that includes thousands of customers -- again, across multiple jurisdictions, not just Kentucky. I only used Kentucky in this case, but I see this in multiple jurisdictions -- is representative of low-income customers, and I'd rather look at actual observations than census track ten-year-old estimates.

VICE CHAIRMAN CHANDLER: Mr. Chairman, I think we need to move on to the confidential session for the last part of the questions that I have.

CHAIRMAN SCHMITT: Let's see. Candace, can we get into confidential session now?

MS. SACRE: The button that I usually push is not letting me.

CHAIRMAN SCHMITT: Initially we're having some problems. So just hold on, and we'll continue to work on it.

MS. VINSEL: Chairman, this would also be a point for Mr. Frye to leave the hearing temporarily. I can let him know when he can come back in. This is a Kentucky Power document, and Mr. Frye has not signed an agreement with Kentucky Power.

CHAIRMAN SCHMITT: Okay. All right.

MR. FRYE: That's correct, Your Honor. So you want me just to dump out of the meeting completely?

CHAIRMAN SCHMITT: Yes, if you would.

MR. FRYE: I will do so, and if someone can just let me know when it's time to come back, I would appreciate it.

CHAIRMAN SCHMITT: Okay. Thank you.

MS. SACRE: Jim is going to check to see if he can do it manually from back there, but my confidential button --

CHAIRMAN SCHMITT: We're still working on it to see if we can get into confidential session.

MR. RHODES: The system is not letting us go

into confidential mode.

(Indiscernible conversation.)

CHAIRMAN SCHMITT: All right. Here's -- here's -- we have a technological problem which prohibits us from going into confidential session at this time. Our IT person is making a telephone call to see what can be done. So we can wait and do that, or we can move on.

I don't know exactly how we do that because I know counsel for Kentucky Power was going to want to conduct a redirect, but apparently something happened to the technology here that we no longer have an option to go into confidential session until something is fixed.

VICE CHAIRMAN CHANDLER: Chairman, can I propose -- I believe that I can ask the majority of my questions. As long as Mr. Vaughan has the document in front of him, his personal document in front of him, I think that I could ask the majority -- I think I can ask all of them on the nonconfidential session because I won't get into the actual numbers, if that's something we'd like to try.

And then Ms. Blend can correct us if we veer off course. We can always go back and edit the film

and take something out if need be.

CHAIRMAN SCHMITT: Why don't we try to do that and see what -- see if we can. And if it doesn't work, we'll just stop and -- till we get it repaired.

Q. So, Mr. Vaughan, let me ask, do you have -- can you get in your possession the Company's response -- confidential response to KPSC 5-6?

A. Probably. Just a moment.

Q. That's okay.

VICE CHAIRMAN CHANDLER: And for Counsel's benefit, your benefit, Mr. Vaughan, on the document, there were tabs at the bottom, and I just would like to talk about the summary page, if we could.

MS. BLEND: Your Honor, this is Ms. Blend. We are pulling up a copy of the document, which is an Excel spreadsheet, electronically. And we'll just need a moment to do so.

VICE CHAIRMAN CHANDLER: That's okay.

MS. BLEND: I'll let you know once we have pulled it up. Thank you.

And while we are pulling up that document, Your Honor, I did just want to mention, in terms of confidentiality, there is the YouTube stream, I believe, that is currently going, and so I will

express some reservation regarding the ability to put confidential information -- or eliminate confidential information from that record inasmuch as some confidential information, you know, if observed by someone on YouTube, cannot be -- (indiscernible).

CHAIRMAN SCHMITT: Once it's on YouTube, there's not much hope of expunging anything. So if we get close to something, I mean, I think it's up to the Vice Chairman and Mr. Vaughan and you, Ms. Blend, if we're getting close to an issue where you think something might be revealed, if you'll let me know or object, I'll stop it immediately, and we'll just wait until we get some other expertise in here to see if we can get the system fixed.

Apparently, it just went off on its own, and the button that would allow us to go into confidentiality -- confidential session disappeared. So we're trying to work on that now, but so -- we can try to go forward, but if there's an issue, we absolutely won't compromise confidentiality.

MS. BLEND: Thank you, Your Honor. I'll just ask is it possible to turn off the YouTube stream just to avoid that particular concern such that we would only need to deal with -- within the video

record?

CHAIRMAN SCHMITT: I don't know. We're sending a runner back now to see if that is possible.

MS. BLEND: Okay. Thank you.

So I'll just remind Mr. Vaughan to be very judicious and careful in his answers to ensure that we don't disclose any confidential information.

VICE CHAIRMAN CHANDLER: Yeah, and I'll just ask, as an initial matter, Ms. Blend, are the -- let me get this right. The rows on the left, the one, two, three, four, five, six, seven different classifications on the left, are those -- just referring to those, never referring to the numbers, confidential in and of themselves?

THE WITNESS: I don't believe so, no.

MS. BLEND: They're not.

VICE CHAIRMAN CHANDLER: Okay. That's primarily what I'm going to be asking about. I'm fairly indifferent to the numbers because I can see them, and I know what they are, and they're in the record. I just need to understand what each one of the rows specifically means as it relates to those numbers.

MS. BLEND: Sure.

THE WITNESS: I have the spreadsheet up at the summary tab.

CHAIRMAN SCHMITT: Is there a ruling on that?

MS. VINSEL: We've got a couple options, Chairman.

Yes, our IT department is able to turn off the YouTube stream and audio, and he's doing that now and checking it. The other option is, if we take a 10-minute recess, he can reboot the system, and, ideally, the ability to go into confidential session would be there.

CHAIRMAN SCHMITT: Were you able to hear Ms. Vinsel? You were?

MS. BLEND: Yes, sir, I was able to hear Ms. Vinsel.

CHAIRMAN SCHMITT: Okay. Well, here's the situation: We can either cut off YouTube audio and video, or we're told that if we can take a 10-minute break we can reboot, and we should be able to get the system back in order.

My suggestion is that we just take a 10-minute break and then see if we can get the system fixed and come back. And then, if we can't, if it doesn't work, then we just, you know, delete YouTube. Okay?

MS. BLEND: Thank you.

CHAIRMAN SCHMITT: That's the best. And, that way, you can go into confidential session. And if not, we can fix it another way. So we'll now be in recess until 12 minutes after 4:00.

MS. BLEND: Thank you, Your Honor.

(Recess from 4:04 p.m. to 4:18 p.m.)

CHAIRMAN SCHMITT: Okay. We're back on the record, and the system has been fixed. Jim Rhodes has managed to get us back to where we could be in confidential session. So if you still want to go into confidential session, Vice Chairman, let me know, and we'll do that right now.

VICE CHAIRMAN CHANDLER: I'd certainly like to try to. If Mr. Frye -- we'll let him speak up for a second.

MR. FRYE: I was just going to say, if we're going to do this, then I will dump back out of the meeting once again.

CHAIRMAN SCHMITT: Oh, I guess that's right. Apparently, your client didn't sign a confidentiality order or something. Is that the --

MR. FRYE: That's correct.

CHAIRMAN SCHMITT: Or agreement, I assume? All right. Well, I'm sorry, Mr. Frye, but if you can drop off one more time, we'll see if we can get

through this.

MR. FRYE: I will do that right now, Mr. Chairman.

CHAIRMAN SCHMITT: All right, Candace. Can we go into confidential session?

MS. SACRE: Okay. We are in confidential.

CHAIRMAN SCHMITT: All right. We're now in confidential session.

(Confidential testimony of Mr. Vaughan heard from 4:19 p.m. through 4:49 p.m.)

CHAIRMAN SCHMITT: Okay. We're now back in public session.

Dr. Mathews, questions?

VICE CHAIRMAN CHANDLER: Chairman, I have one more question.

CHAIRMAN SCHMITT: Oh, I'm sorry.

COMMISSIONER MATHEWS: Vice Chairman isn't done.

CHAIRMAN SCHMITT: I didn't want to interfere with your objection. Go ahead.

Q. Last question I have, Mr. Vaughan, is on the weather normalization adjustment you made as a test year adjustment. Are you aware of what I mean when I say that?

A. I am.

Q. And what is the basis of that? I'm unaware, and I'll plead my ignorance, if the Commission has ever approved that as it relates to an electric utility.

So I'm just curious. Is this something that you've offered in the past, that you've done in other states? Is this something that maybe Kentucky Power has done in previous cases I'm unaware of?

I'm just curious if you can speak to that normal weatherization -- weather normalization adjustment.

A. Yes, certainly. We did include this in at least the last base rate case, potentially the one before that as well, but this is a common adjustment we make in our retail jurisdictions where, right, weather can drive, negatively or positively, drive sales.

And so when you're trying to set rates, you want to use billing units, you know, as the basis for that, those rates that are, in theory, weather-normal, right? So you're indifferent to weather.

And our load forecasting group does a lot of studies around this, and they are the ones that provide us with, you know, heating degree days and

cooling degree days and come up with what the actual impact of weather was on our sales over any period of time. And they use 30-year normal weather measure as the basis for that.

So this -- this adjustment in this rate case increased revenues by $4.2 million because our weather was below normal from the test year. And so, again, with that you -- you don't just look at revenues in -- because it really, underneath it, you're adjusting sales units, and so you also look at the variable cost of those sales units.

So there's kind of two parts to it. You increase or decrease retail sales revenues, and you increase or decrease to some percent variable operating expenses that go with them. So the net effect of this adjustment is about a $1.2 million reduction in the revenue requirement.

Q. So I guess I'm confused. What's the $4.2 million amount, and what's the 1.2 million you said?

A. If you look at page 46 of my direct testimony where I discuss this adjustment, retail revenues increased by 4.2 million, but then, accordingly, you also adjust operation and maintenance expense for variable -- variable O&M you would have incurred,

which is energy supply costs, as you adjust the level in sales by 2.8 million.

So revenues go up by 4.2, expense goes up by 2.8, the net effect is $1.2 million, essentially a decrease in the revenue requirement.

VICE CHAIRMAN CHANDLER: Okay. All right. Thank you very much.

Sorry, Commissioner Mathews. I apologize.

CHAIRMAN SCHMITT: Commissioner Mathews, questions?

COMMISSIONER MATHEWS: I can't imagine there's anything that has been not asked, so I have no questions.

CHAIRMAN SCHMITT: All right. Ms. Blend, I suspect that you have redirect; is that correct?

MS. BLEND: That's correct, Your Honor.

CHAIRMAN SCHMITT: Your client was on the stand for a couple hours or so yesterday and all day today. Would you like -- we can recess and come back in the morning, especially if you'd like some time to talk to your witness in view of the examination, or we can -- you can go forward now. It's up to you.

MS. BLEND: Your Honor, we'll take your offer and plan to conduct redirect first thing tomorrow

morning.

CHAIRMAN SCHMITT: Okay. All right. We'll be in recess until 9:00 in the morning, and, hopefully, we can finish this case tomorrow. We'll see everybody at 9:00 a.m.

MS. BLEND: Thank you, Your Honor.

(Hearing adjourned at 4:53 p.m.)

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STATE OF KENTUCKY)
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COUNTY OF JEFFERSON)

We, Laura J. Kogut and Jennifer R. Janes, Notaries Public within and for the State at Large, with commissions expiring 25 July 2023 and 1 May 2023 respectively, do hereby certify that the foregoing hearing was taken before us at the time and place and for the purpose in the caption stated; that witnesses were first duly sworn to tell the truth, the whole truth, and nothing but the truth; that the hearing was reduced by us to shorthand writing; that the foregoing is a full, true, and correct transcript of the hearing to the best of our ability; that the appearances were as stated in the caption.

WITNESS our hand this 30th day of November 2020.

Laura J. Kogut, RMR, CRR, CRC
Notary Public, State at Large

Jennifer R. Janes, RPR, CRR, CRC
Notary Public, State at Large