BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the :
Application of Columbus :
Southern Power Company for:
Approval of its Electric :
Security Plan; an : Case No. 08-917-EL-SSO
Amendment to its Corporate:
Separation Plan; and the :
Sale or Transfer of :
Certain Generating Assets.:
:
In the Matter of the :
Application of Ohio Power :
Company for Approval of :
its Electric Security : Case No. 08-918-EL-SSO
Plan; and an Amendment to :
its Corporate Separation :
Plan. :

- - -

PROCEEDINGS

before Ms. Kimberly W. Bojko and Ms. Greta See, Hearing Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, called at 10:00 a.m. on Monday, December 1, 2008.

- - -

VOLUME IX

\- - -

ARMSTRONG & OKEY, INC.
185 South Fifth Street, Suite 101
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

APPEARANCES:

American Electric Power
By Mr. Marvin I. Resnik
Mr. Steven T. Nourse
One Riverside Plaza
Columbus, Ohio 43215-2373

Porter, Wright, Morris & Arthur, LLP
By Mr. Daniel R. Conway
41 South High Street
Columbus, Ohio 43215-6194

On behalf of Columbus Southern Power and Ohio Power Company.

Janine L. Migden-Ostrander
Ohio Consumers' Counsel
By Ms. Maureen R. Grady
Mr. Terry L. Etter
Ms. Jacqueline Lake Roberts
Mr. Michael E. Idzkowski
Mr. Richard C. Reese
Assistant Consumers' Counsel
Ten West Broad Street, Suite 1800
Columbus, Ohio 43215-3485

On behalf of the Residential Ratepayers of Columbus Southern Power and Ohio Power Company.

Sherry Maxfield, First Assistant Attorney General
Duane W. Luckey
Senior Deputy Attorney General
Public Utilities Section
By Mr. Werner L. Margard III
Mr. John H. Jones

Mr. Thomas G. Lindgren
Assistant Attorneys General
180 East Broad Street, 9th Floor
Columbus, Ohio 43215-3793

On behalf of the staff of the Public
Utilities Commission of Ohio.

APPEARANCES (Continued):

Mr. Richard L. Sites
General Counsel, Ohio Hospital Association
155 East Broad Street, Floor 15
Columbus, Ohio 43215-3620

Bricker & Eckler, LLP
By Mr. Thomas J. O'Brien
100 South Third Street
Columbus, Ohio 43215-4291

On behalf of the Ohio Hospital Association.

Mr. Joseph V. Maskovyak
Mr. Michael R. Smalz
Ohio State Legal Services Association
555 Buttles Avenue
Columbus, Ohio 43215

On behalf of the Appalachian People's Action Coalition.

McNees, Wallace & Nurick
By Mr. Samuel C. Randazzo
Ms. Lisa McAlister
Mr. Joseph M. Clark
Fifth Third Center, Suite 1700
21 East State Street
Columbus, Ohio 43215

On behalf of the Industrial Energy Users of Ohio.

McDermott, Will & Emery
By Ms. Grace C. Wung
600 Thirteenth Street, NW

Washington, DC 20005-3096

On behalf of Wal-Mart Stores East, LP, Macy's, Inc., Sam's East, Inc.

APPEARANCES (Continued):

Boehm, Kurtz & Lowry
By Mr. David Boehm
Mr. Michael Kurtz
36 East Seventh Street
Suite 1510
Cincinnati, Ohio 45202-4454

On behalf of the Ohio Energy Group.

Chester, Willcox & Saxbe, LLP
By Mr. John W. Bentine
Mr. Matthew S. White
Mr. Mark S. Yurick
65 East State Street
Columbus, Ohio 43215

On behalf of the Kroger Company.

Bell Royer, Co., LPA
Mr. Langdon D. Bell
33 South Grant Avenue
Columbus, Ohio 43215-3927

On behalf of the Ohio Manufacturers Association.

Bell Royer, Co., LPA
Mr. Barth E. Royer
33 South Grant Avenue
Columbus, Ohio 43215-3927

On behalf of the Ohio Environmental Council and Dominion Retail.

Schottenstein, Zox & Dunn
By Mr. Andre Porter

Mr. Christopher Miller
Mr. Gregory Dunn
250 West Street
Columbus, Ohio 43215-2538

On behalf of the Association of
Independent Colleges and Universities of
Ohio.

APPEARANCES (Continued):

Vorys, Sater, Seymour and Pease, LLP
By Mr. M. Howard Petricoff
Mr. Michael J. Settineri
Ms. Betsy L. Elder
52 East Gay Street
Columbus, Ohio 43216-1008

Mr. Bobby Singh
300 West Wilson Bridge Road
Worthington, Ohio 43085

On behalf of Integrys Energy.

Vorys, Sater, Seymour and Pease, LLP
By Mr. M. Howard Petricoff
Mr. Michael J. Settineri
Ms. Betsy L. Elder
52 East Gay Street
Columbus, Ohio 43216-1008

Ms. Cynthia Fonner
500 West Washington Boulevard
Chicago, Illinois 60661

On behalf of the Constellation NewEnergy
and Constellation Commodity Energy Group.

Vorys, Sater, Seymour and Pease, LLP
By Mr. M. Howard Petricoff
Mr. Michael J. Settineri
Ms. Betsy L. Elder
52 East Gay Street
Columbus, Ohio 43216-1008

On behalf of EnerNoc, Inc. and
Consumer Powerline.

Vorys, Sater, Seymour and Pease, LLP
By Mr. M. Howard Petricoff
Mr. Michael J. Settineri
Ms. Betsy L. Elder
52 East Gay Street
Columbus, Ohio 43216-1008

On behalf of the Ohio Association of
School Business Officials.

APPEARANCES (Continued):

Mr. David C. Rinebolt
Ms. Colleen Mooney
231 East Lima Street
P.O. Box 1793
Findlay, Ohio 45839-1793

On behalf of Ohio Partners for Affordable Energy.

- - -

INDEX

- - -

- - -

INDEX

- - -

- - -

Monday Morning Session,
December 1, 2008.

- - -

EXAMINER BOJKO: Let's go on the record.

Good morning. This is the continuation of case numbers 08-917, 08-918-EL-SSO In the Matter of AEP's Electric Security Plans, et al.

At this time let's take abbreviated appearances.

MR. RESNIK: For the companies, Marvin Resnik and Dan Conway. Mr. Nourse will be here in spirit but not physically today.

EXAMINER BOJKO: Mr. Smalz.

MR. SMALZ: For the Appalachian People's Action Coalition, Michael Smalz and Joseph Maskovyak.

MR. O'BRIEN: On behalf of the Ohio Hospital Association, Rick Sites and Tom O'Brien.

MR. MARGARD: Werner Margard, John Jones, Tom Lindgren, assistant attorneys general, on behalf of the Commission staff.

MR. SETTINERI: On behalf of the Competitive Suppliers Group, Michael Settineri, Howard Petricoff, and Betsy Elder.

MS. GRADY: On behalf of the residential ratepayers of the companies, Janine Midgen-Ostrander, Consumers' Counsel, Maureen R. Grady, Michael Idzkowski, and Jacqueline Roberts.

MR. RANDAZZO: Lisa McAlister, Joseph Clark, and Sam Randazzo on behalf of the Industrial Energy Users-Ohio. Thank you.

MS. WUNG: On behalf of the Commercial Group, Grace Wung.

MR. RINEBOLT: On behalf of the Ohio Partners for Affordable Energy, David C. Rinebolt and Colleen L. Mooney.

MR. BOEHM: On behalf of the Ohio Energy Group, David Boehm and Michael Kurtz.

MR. BELL: On behalf of the Ohio Manufacturers Association, Langdon Bell.

MR. WHITE: On behalf of Kroger Company, John Bentine, Mark Yurick, and Matt White.

EXAMINER BOJKO: Thank you.

I believe the company is going to call their next witness at this time.

MR. CONWAY: Thank you, your Honor.
At this time the companies call David M. Roush.

EXAMINER BOJKO: Mr. Roush, please raise your right hand.

(Witness sworn.)

EXAMINER BOJKO: Please sit down.

\- - -

DAVID M. ROUSH

being first duly sworn, as prescribed by law, was examined and testified as follows:

DIRECT EXAMINATION

By Mr. Conway:

Q. Good morning, Mr. Roush. Could you state your full name for the record, please?

A. My name is David M. Roush.

Q. And, Mr. Roush, by whom are you employed?

A. I'm employed by American Electric Power Service Corporation.

Q. And your position is what?

A. Manager of regulated pricing and analysis.

Q. Mr. Roush, did you prepare or have prepared under your direct supervision and prefile direct testimony for this proceeding?

A. I did.

Q. And is that the same testimony that we I believe marked previously in the initial phase of the hearing as Companies' Exhibit No. 1, which included your narrative testimony and the attached exhibits to that testimony, DMR-1 through 11?

A. That's correct.

Q. Do you have any corrections or additions to make to your testimony or exhibits at this point?

A. No, I do not.

Q. Mr. Roush, if I were to ask you the questions in your direct prefiled testimony, which has been marked as Companies' Exhibit No. 1 today, would your answers be the same as they appear in that document?

A. Yes, they would.

Q. And are they true and correct to the best of your belief and knowledge?

A. Yes, they are.

MR. CONWAY: Your Honor, at this time I would offer Mr. Roush for cross-examination and also move the admission of his direct testimony and attached exhibits subject to cross-examination.

EXAMINER BOJKO: Let's begin this morning with Mr. Smalz.

MR. RANDAZZO: Your Honor, before we start, I have one motion to strike.

EXAMINER BOJKO: Okay.

MR. RANDAZZO: It's at page 7, lines 14 through 19.

EXAMINER BOJKO: Grounds?

MR. RANDAZZO: He's simply quoting the PJM market monitor who is not testifying here.

EXAMINER BOJKO: Does the company wish to respond?

MR. CONWAY: Your Honor, what Mr. Roush is doing at this point is indicating his agreement with the statement made by the PJM market monitor. I think it's appropriate to explain the basis for his position, and I think it's relevant and is helpful to the Commission's understanding and disposition of the related issue.

MS. GRADY: I would join Mr. Randazzo and believe that it is hearsay and there is no exception to the hearsay rule that is covered by this. It's an out-of-court statement made by the declarant offered to prove the truth of the matter asserted, and if it is not hearsay, then we could admit it just on the basis of not for the truth of the matter asserted.

EXAMINER BOJKO: Would you like to

respond to that?

MR. CONWAY: Your Honor, I think that the point of the testimony is to indicate Mr. Roush's agreement, as I just mentioned, with the statement of the market monitor. As far as whether or not it's being offered for the truth of the matter asserted, I would say that it's not being offered for that purpose but it is offered as a comment made by a relevant authoritative source. It's a publicly filed document, and you even can take administrative notice of it if you prefer to do that, but I think it's entirely appropriate for him to indicate that he's in agreement with it, with the statement.

EXAMINER BOJKO: With that assertion that it's not offered for the truth of the matter and that it's to demonstrate agreement or to state Mr. Roush's position on the matter, we're going to allow -- we're going to deny the motion to strike and leave it in.

MR. RANDAZZO: So that I'm clear, for purposes of cross-examination then, the statement here that the economic program has nothing to do with retail rate issues is not being offered for the truth of the matter asserted?

EXAMINER BOJKO: You can question the witness based on his position on the matter.

MR. RANDAZZO: Okeydoke. Thank you.

EXAMINER BOJKO: Anything else?

Okay. You may begin cross-examination, Mr. Smalz.

MR. SMALZ: I have no questions of Mr. Roush, your Honor.

EXAMINER BOJKO: Mr. O'Brien?

MR. O'BRIEN: Thank you, your Honor.

\- - -

CROSS-EXAMINATION

By Mr. O'Brien:

Q. Good morning, Mr. Roush.

A. Good morning.

Q. Could you turn, please, to your testimony at page 5? This portion of your testimony pertains to the company's interruptible service offerings. On line 10 you indicate that the current emergency curtailable service program has experienced only meager interest from potential participants. Do you have an opinion as to why that might be the case?

A. Yes, I do. There are a couple provisions within the existing ECS rider that I think customers could have viewed as a reason not to participate. The primary one that comes to mind is referenced on lines 14 through 16 of my testimony where I discuss the failure to curtail charge that existed within the current ECS rider.

The other item that I would view as restricting interest was the restriction in the current tariff ECS rider to have only 3-megawatt and larger interruptible load, whereas under the proposed rider we had 1 megawatt, so those two are two areas I viewed that would have caused meager interest.

Q. Following up on that response, how do you view the significant modifications that the company's proposing to this program, how do you believe those will increase participation? You just mentioned one of the reasons. Are there any others?

A. I believe with respect to the emergency curtailable service rider, the two primary ones would be the increase in the availability to smaller size customers, we're removing the charge for noncompliance or failure to curtail, and then the third area would be the existing ECS rider had basically stated prices depending on the option the customer selected.

The new rider now has that the price will be quoted at the time of the event. When this rider was established several years ago, you know, stated prices were set and it, just in my mind, makes much more sense to have the price quoted at the time of the event than to have a stated price that was established six, seven, eight years ago within the context of the rider.

Q. Okay. Thank you.

These next questions I'm going to ask you pertain to the net metering service for hospitals that are contained in your testimony beginning at page 8 and 9, or they're referenced in your testimony beginning at pages 8 and 9. Is it correct that the conditions in the tariff require the facilities that would be used in this program to be owned by the program participant?

A. The condition within the tariff is that one of the requirements is that it is owned and operated by the customer and is located on the customer generator's premises. And the basis for that, the entire net energy metering service hospital tariff was basically to take the company's existing net energy metering service tariff as it was approved and make the modifications to it that the legislation required to provide a specific net metering provision for hospitals.

Q. Thank you.

Can you tell me the date on which the

current tariff was approved by the Commission?

A. No, I cannot off the top of my head.

Q. Can you give me a general sense of how old that tariff is?

A. I think roughly five or six years, and then we also have a modification that's pending before the Commission that came out of the 05-1500-EL-COI cases that required us to make modifications to that tariff, and I address that in my testimony, that those modifications would be incorporated in these tariffs once they're approved.

Q. Other than the fact that this restriction was contained in a previously approved tariff, can you think of any other basis from which this restriction is derived?

A. Obviously, I'm not a lawyer, and reading Senate Bill 221 and also reading Senate Bill 3, kind of the way I read the definitions, you know, they talk about a customer generator, and the only customer at the site for the company is the customer, so kind of from the framework of the definitions contained within the legislation, that's kind of the basis for my understanding.

Q. Thank you.

Now, I would turn your attention to your

discussion on page 8 of your testimony concerning
alternate feed service. On line 10 of your testimony
on page 8 you state that -- well, you characterize
AFS service as an optional premium service.

Just a question clarifying. I believe
there is a definition of "premium service" in your

tariff. Would this reference to premium service tie back to that definition in the tariff?

A. To be clear, the definition you're referencing is on the Columbus Southern sheet 3-14?

Q. Correct.

A. Under the line extension provisions, no, I would not draw the parallel between premium service in the context of AFS and premium service in the context of line extensions. The premium service definition that's included in the context of line extensions is for -- well, let me read it just to be precise: "All additional expenses incurred by the Company to provide service to the customer, where such costs are over and above the Company designed Basic Service Plan. While the following is not all inclusive, these costs will be such things as customer requested alternate construction routes, underground facilities, special construction, excess cost, additional equipment, additional expenses incurred due to legislation, local ordinances and/or restrictions, as well as any expenses imposed on the company beyond the company's control."

The context of that definition is when we're establishing service to the customer, the company comes up with a basic service plan, and if the customer says, "Well, your basic service plan is overhead. I really would like underground," that's a premium service to provide the underground.

If the customer says, "Well, your basic service takes this route. I'd really you rather route the service along this line or route," then the additional cost of that would be a premium service.

AFS, on the other hand, there is a component of it that is related to a premium service in that there are dedicated local facilities that may be needed to provide AFS. When I'm using "premium service" in the context of AFS, it's akin to the type of definition we're talking about in line extension only we're really taking it a step further.

It's saying not only does the customer want something other than just normal basic plan connection, it wants a level of redundancy above and beyond that, and that level of redundancy can consist of two pieces of costs, dedicated local facility costs and then also just the fact that they are now reserving capacity on another set of distribution transformers, distribution circuitry, et cetera. So they're akin but they're not identical.

Q. Thank you.

Were you responsible for developing the

rates that are reflected in the new AFS services tariff attached to your testimony?

A. Yes, I was.

Q. Can you describe for me generally how those rates were developed?

A. Certainly. The rates were developed based upon the cost information from each of the companies' last rate case and, you know, coming out of the cost-of-service studies you get functional cost information, which is basically the costs related to each type of service, whether it be the secondary function, the primary function, the sub-transmission function, transmission function, et cetera.

So in looking specifically at standard AFS, which is redundant primary circuit, redundant primary transformation, that's basically the costs that would be included in the distribution primary cost function in the cost-of-service study. So you take the cost included within that function, you know, unitize that based upon megawatts of demand or kW of demand to come up with a per-unit rate, and that per-unit rate is effectively implicit in all customers' current rates, and that same per-unit rate would apply to AFS customers, would apply to a new customer taking service just on a basic service plan. So we're consistently applying the same per-unit cost for reservation of capacity on those primary distribution facilities.

Now, there's additional rates. The same methodology applies. There's some additional rates that are included in the tariff for nonstandard AFS, and they were developed using that same method.

MR. O'BRIEN: Your Honor, may I approach the witness?

EXAMINER BOJKO: You may.

MR. O'BRIEN: I would ask the court reporter to mark this document as OHA Exhibit No. 2.

EXAMINER BOJKO: It will be so marked for identification purposes.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, do you recognize the document I handed you that has been marked as OHA Exhibit No. 2?

A. Yes, I do.

Q. This is a response to an Ohio Hospital Association interrogatory request. Did you prepare this response?

A. Yes, I did.

Q. Does this exhibit generally illustrate how the rates for this service were derived?

MR. O'BRIEN: For the record, the interrogatory and attached two pages, one that covers Ohio Power and the other that covers Columbus Southern.

A. Yes, it does. As you note in the header, you know, both of these calculations were based upon costs from the '94 case for Ohio Power and the '91 case for CSP.

Q. Mr. Roush, I want to back up just a second. Can you describe for the record in a very, very high level what alternate feed service actually does for a customer?

A. Certainly. I think it's probably best to start with the definition kind of in the availability of service of the schedule. Alternate feed service is a premium service available to customers served under schedules GS-2 and GS-3 -- I'm reading from Columbus Southern Power's tariff -- who request an

AFS from existing distribution facilities which is in addition to the customer's basic service, provided that the company can reasonably provide available capacity from alternate distribution facilities.

What that really means to me is that normal standard service to a customer is through a distribution station, distribution line, a single set of facilities providing that to the customer in most circumstances.

When the company is requested to provide an alternate feed for a standard alternate feed, what the customer is asking for and what the customer would get would be a second set of transformation, a second set of primary circuitry to come into their facility. And what would happen would be if their normal service is from -- I've got to use my hands and talk to do this because it's much more easy for me to see visually.

If their normal circuit is from a station here and the line comes in and their meter's right here and their alternate feed would be, say, from another station over here, and the line comes in and meets, and then there's a transfer switch that's sitting there, and so the customer normally is served off of this circuit. If that circuit is out, say a tree falls on that circuit, then if they have an automatic transfer switch, they just flop over to this other circuit and their power would only be out momentarily.

If they -- and then they would stay on that other circuit until this circuit got fixed.

When that circuit got fixed, with an automatic transfer switch they flip right back to their main circuit. So it's kind of a redundant level of an attempt to eliminate points of failure, you know.

Q. Now, let me ask you a hypothetical question.

A. Certainly.

Q. If a customer's currently being served by their primary feed as opposed to the secondary feed, what would the load be on the secondary feed at that time?

MR. CONWAY: Just a point of clarification. When you use the word "secondary," are you using alternative as opposed to a voltage differentiation?

MR. O'BRIEN: Yes. Thank you for that clarification, counsel.

A. I believe you're asking me what is the load that the customer's placing on their standard circuit during just normal operations. It would be, you know, whatever their load was at any given point in time.

Q. So if a customer's operating on their primary feed, there would still be -- would there be load on the alternative feed?

A. The customer -- while the customer is being served from their primary feed, there would be no load from that customer on the alternate feed circuit, but there could be other loads on that circuit.

Q. And conversely, if that customer were operating on their alternate feed because there was some issue with the primary feed, there wouldn't be a load on the primary feed at that same time, would there?

A. No, there would not. And I guess the relevance of that to alternate feed service really is that both circuits have to have adequate capacity to serve that customer's load, so the primary feed by definition has to have adequate capacity, and when the customers request an alternate feed, then the alternate feed transformer and circuitry also has to have adequate capacity to meet that customer's load.

Q. Thank you for that.

EXAMINER BOJKO: Can everybody hear Mr. O'Brien?

MR. O'BRIEN: Yeah, it occurred to me I'm operating without a microphone this morning.

EXAMINER BOJKO: Put one in front of you.

You trail off sometimes.

MR. RANDAZZO: So does the witness.

MR. O'BRIEN: I'm often known by my nom de guerre "Mumbles."

MR. RANDAZZO: What did you say?

MR. O'BRIEN: Much better.

Q. (By Mr. O'Brien) Turning to what has been marked as OHA Exhibit No. 2, and it doesn't matter whether we go with page -- the Columbus Southern sheet or the Ohio Power sheet, where you have your derivation of rates for both secondary and primary service, you have a Coincident Demand column. Do you see that?

A. Yes, I do.

Q. Does that indicate that you used the coincident peak demand for the customer to calculate the demand component of the rate?

A. Yes. The demand component of the rate is calculated based upon the coincident demand in aggregate basically of all customers at the times of the peak from looking at primary, on the primary distribution system.

Q. Can you tell me why you used coincident peak as opposed to, say, noncoincident peak in this calculation?

A. Yes. The use of coincident peak, particularly in the calculation of the AFS, is that when you are looking at designing the station's circuit and reserving capacity on there for an alternate feed service customer, you have to, for planning purposes I think, assume, you know, the worst case, which is that the customer's primary circuit fails at the time of the peak, in which case you have to have adequate capacity on the alternate circuit in order to be able to keep the customer on line, so it kind of syncs up with the planning criteria, is the way I view it.

Q. In making that determination did you perform any studies of how often AFS service would be required simultaneously with the system peak load?

A. No, I didn't do any studies. I didn't think it was necessary. It's kind of more of a logical connection for me.

MR. O'BRIEN: Thank you, your Honor.

That's all the questions I have.

EXAMINER BOJKO: Thank you.

MR. O'BRIEN: Thank you, Mr. Roush.

THE WITNESS: Thank you.

EXAMINER BOJKO: Mr. Petricoff or Mr. Settineri.

MR. PETRICOFF: Mr. Settineri will do the cross. Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Settineri:

Q. Good morning, Mr. Roush.

A. Good morning.

Q. Mr. Roush, at page 6 of your testimony, line 16 to 17 --

EXAMINER BOJKO: I'm sorry, page?

MR. SETTINERI: Page 6, line 16 to 17.

Q. -- you note that PJM offers a number of wholesale demand response programs. Do you see that?

A. Yes, I do.

Q. Are you familiar with the PJM demand response programs?

A. Yes, I am. I wouldn't consider myself a total expert at all the minutia within the programs, but I've spent a lot of time with them, yes.

Q. And are you familiar in general with the potential benefits of demand response programs?

A. I guess if you're asking me, you know, from a general standpoint do I have an understanding and view of how demand response can be beneficial, yes, I do.

Q. Would you agree with me that demand response programs can reduce price volatility?

A. I guess specifically within the construct of wholesale markets I would agree with that statement, that the demand response programs can reduce wholesale market price volatility.

Q. Would you agree with me that demand response programs can improve grid reliability?

A. I would agree with you that some demand response programs can be designed to improve grid reliability. I would also believe that there are some demand response programs which I'm aware of that I do not believe improve grid reliability.

Q. Are you familiar with the PJM demand response program the ILR program, interruptible load for reliability program?

A. Yes, I am.

Q. Would that program be a program that would improve grid reliability?

A. I think that used to be a straightforward
answer where I would say yes, that the interruptible
load for reliability program can improve grid
reliability, but as I think about it today I'm not
necessarily sure it does as much as it may -- as the
old ALM program might have in the past in that now

that interruptible load, particularly interruptible load for reliability under that program, is used or treated in the same way as capacity or steel in the ground from generation that, you know, today I don't see -- I mean, it seems to almost be on a level playing field with generation, so in and of itself there's no extra benefit towards reliability and, in fact, that would be effectively offsetting or equivalent to generation.

So I think the question might have been an unequivocal yes in the past. Sitting here thinking about it today, I'm not sure it's that unequivocal. I think it provides the same level of reliability, at least from PJM's standpoint, subject to certain adjustment factors as generation plant would.

Q. But, Mr. Roush, would you agree with me that there is some benefit to the ILR program in regards to grid reliability?

A. I guess -- I would say the benefit of the ILR program today is within a few subtleties towards grid reliability. I don't think that the benefit is any different from a PJM standpoint of, say, a peaker. So I think they're both treated from PJM's standpoint as capacity, and whether that, you know, capacity in and of itself by its very nature, the more capacity you have, the more reliable the grid is.

Q. Mr. Roush, my question was simply do you believe there is some benefit to the ILR program?

A. For who?

Q. Some benefit to the grid in regards to grid reliability.

A. Okay, I wanted to be clear.

Q. You testified earlier that there is not extra benefit. That would indicate there was some benefit. I just want to clarify you would agree there is some benefit with the ILR program with regards to grid reliability.

A. Yes, absolutely there is a benefit from demand response, particularly from capacity-related demand response for grid reliability. I just don't know that there's an extra benefit. I think PJM kind of views it equivalent to a generator, so by its

existence it does have benefits toward grid
reliability.
Q. And again, in general in regards to
demand response programs, in the event of an
emergency on the grid, could demand response programs
be utilized as opposed to going to other steps like

rolling blackouts?

THE WITNESS: Could you read the question back?

(Record read.)

A. With the caveat that we have to -- you kind of said in general about demand response programs. Demand response programs that have that priority within, say, an emergency operating plan can be utilized to avoid going deeper into an emergency operating plan like rolling blackouts. There are demand response programs that don't necessarily have that feature within them.

EXAMINER BOJKO: Mr. Roush, your microphone's --

THE WITNESS: It's dead.

Thank you. Better?

EXAMINER BOJKO: Yes.

Q. All right. Mr. Roush, do you agree with the following statement: Demand response can provide competitive pressure to reduce wholesale power prices, increase awareness of energy usage, provides for more efficient operation of markets, mitigates market power, and enhances reliability?

THE WITNESS: Would you mind reading that back? It's a long one.

EXAMINER BOJKO: Maybe you could break it out and ask him about each specific item, Mr. Settineri.

MR. SETTINERI: I'd be glad to.

Q. Mr. Roush, do you agree that demand response can provide competitive pressure to reduce wholesale power prices?

A. Yes; with a caveat that it has to be properly designed. I've seen demand response programs that were designed in a way that they did not achieve that end.

Q. Mr. Roush, do you agree that demand response can provide -- strike that.

Mr. Roush, do you agree that demand response can increase awareness of energy usage?

MR. CONWAY: Mr. Settineri, just another point of qualification. You asked whether demand response has an effect. Are you referring to demand response programs or not?

MR. SETTINERI: That is correct, demand
response programs.

A. I guess I would agree they could
increase -- let me get the words right. Was it
awareness of energy usage? Were those the terms you
used?

Q. Yes.
A. I believe they could. I'm not certain they have to, but they could.
Q. Mr. Roush, turning to page 5 of your testimony, lines 6 through 9, you state that: "AEP-Ohio proposes to expand the availability of Ohio Power's existing schedule IRP-D, Interruptible Power - Discretionary, from the current limit of 256 megawatts to 450 megawatts." Do you see that?
A. Yes, I do.
Q. Isn't it true that you have not done any forecasts as to how many new customers will take service under schedule IRP-D because of the proposed expansion from 256 megawatts to 450 megawatts?
A. I have not projected how many new customers may sign up. No, I have not.
Q. In fact, isn't it true that as of today there are only six Ohio Power Company customers and One Columbus Southern Power customer on schedule

IRP-D?

A. Going from memory those numbers sound correct to me.

Q. In regards to changing the limits under schedule IRP-D, am I correct that Columbus Southern Power's limit was not changed because current

subscription is nowhere near that level?
A. I believe if you read lines 8 and 9 on my testimony on page 5 it says: "CSP's current limit was not changed since the limitation has not been a constraint." I think the existing limit, I believe, is 75 mVA. We currently have between 10 and 20 mVA participating under that tariff.
Q. Mr. Roush, on page 5 of your direct testimony, lines 10 to 14, you note that customers have shown meager interest in the companies' emergency curtailable service and price curtailable service rider offerings. Do you see that?
A. Yes, I do.
Q. Okay. Isn't it true that as of today there is only one Ohio Power customer participating on the price curtailable service rider?
A. I believe that's correct.
Q. And that customer is the only customer that participated in the price curtailable service

rider since 2000, correct?

A. I believe one other customer participated back in 2000, but that's I think the extent of my memory.

Q. Mr. Roush, isn't it true that neither Ohio Power or Columbus Southern Power have any customers on the emergency curtailable service rider currently?

A. That is correct.

Q. Mr. Roush, isn't it true that not one customer's participated in the emergency curtailable service rider over the last eight years?

A. I believe that -- and that's where my memory gets a little fuzzy, is whether the other customer that participated in 2000, whether they were ECS or PCS.

Q. Okay. Mr. Roush, isn't it true that there have been curtailments under IRP-D 2006 through 2008?

THE WITNESS: Could you read that one back?

(Record read.)

A. Yes, there have. And I just want to make sure that we're clear on that. There are two different ways that -- at least two different ways a customer can be requested to curtail under schedule IRP-D. There's the emergency type interruption where the customer has no choice but to reduce, and then there's the replacement electricity type interruption where the customer has the option to either reduce usage or pay a quoted price to continue operating.

My recollection is all of the interruptions that have occurred during that 2006 to 2008 period have been the latter where the customer chose whether to continue operating or not based upon the quoted price.

MR. SETTINERI: May I approach?

EXAMINER BOJKO: You may.

MR. SETTINERI: I'd like to ask the court reporter to mark this as Integrys Exhibit 3.

EXAMINER BOJKO: It will be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, do you recognize this document?

A. Yes, I do.

Q. And can you describe it for me?

A. The document is for Columbus Southern and Ohio Power schedule IRP-D. It's Discretionary Interruptions for January 1, 2006, to November 11, 2008, and it lists the start date and time and the event length for that period of time.

Q. Mr. Roush, am I correct that this document was attached to an interrogatory response that you prepared?

A. Yes, it was.

Q. And to the best of your knowledge the

information on this document is accurate?
A. Yes, it is.
Q. Okay. In regards to the discretionary interruptions listed on this document you stated earlier there are two different types. Could you tell me what type of discretionary interruptions these are?
A. These are the second type, which is what I was hoping to clarify in my previous answer. These are the type where the customer has the option to pay the replacement electricity price and continue running or not pay the replacement electricity price and reduce load.
Q. Is this often called economic interruption?
A. Yes, I've heard that term used for it.
Q. Under these interruptions was the company able to devote that energy to making sales to other customers?

A. I'm not sure I can agree with that.
Under these types of interruptions, if the customer reduced load, chose to reduce load instead of purchase replacement electricity, I don't know that automatically translates into additional sales for the company as it may be an avoided purchase for the

companies instead.

Q. Would that potential at least exist?

A. It could.

Q. And could those sales be off-system sales?

A. I guess continuing down the hypothetical, yes, they could.

Q. Mr. Roush, at line 12, page 5 of your testimony you state that: "AEP Ohio proposes significant modifications to the existing offerings." Do you see that?

A. I'm sorry, I lost your reference.

Q. I'm sorry.

A. Did you say page 12?

Q. Page 5, line 12, your direct testimony, you state that: "AEP Ohio proposes significant modifications to the existing offerings." Do you see that?

A. Yes, I do.

Q. And to clarify, the existing offerings you are referring to in that sentence are the emergency curtailable service rider and the price curtailable service rider, correct?

A. That is correct.

Q. Am I correct that for both riders the modifications made to each were similar for Columbus Southern Power and Ohio Power?

A. Yes, the changes were substantially the same for both companies.

Q. Now, am I correct that one change to the emergency curtailment service rider is that the curtailable hour credit was being changed from a stated rate to a quoted price during the time of the event? When I say "event," I mean the curtailment event.

THE WITNESS: Would you mind reading that back?

(Record read.)

A. Yes, that's correct. I'm not sure the terminology was quite right, but the intent was right, that the curtailment credit will be quoted to the customer upon notice of a curtailment event as shown on sheet No. 71-3 which is page 138 of Exhibit DMR-9 -- I'm looking at Columbus Southern -- and that replaced the stated prices that were shown on page 137 of Exhibit DMR-9.

Q. Isn't it true that the customer electing to participate in that rider would not know the curtailment quote prior to enrolling and prior to the curtailment event?

MR. CONWAY: Could I have that question reread, please?

EXAMINER BOJKO: You may.

(Record read.)

A. The customer would not know the credit prior to enrolling. They would be notified of the price in advance of the actual curtailment event itself, I guess, just to be precise.

Q. When you say "in advance," would that be immediately before the curtailment event?

A. I guess turning to page 135 of Exhibit DMR-9, the notice provision there is item 2 that says: "The Company will endeavor to provide as much advance notice as possible of curtailments. However, the customer's ECS load shall be curtailed within 30 minutes if so requested."

So they would know at least 30 minutes in advance of when they needed to curtail of what the price would be, but potentially longer, further in advance.

Q. And isn't it true that the curtailment quote could be higher or lower than the current rate in tariff depending on the circumstances at the time of the curtailment?

A. I would agree that sitting here today, I can't tell you what the price in a given event is going to be so it could be higher or lower than the old stated prices. My gut instinct would be I would suspect it would generally be higher, if not always higher.

Q. Turning to page 143 of 285, DMR-9.

A. Page 133?

Q. I'm sorry, page 143.

A. 143, I'm sorry.

Q. Exhibit DMR-9.

A. Okay, I'm there.

Q. Isn't it true that one modification made here was that the monthly credit payable to a customer participating in this rider will be equal to the sum of the curtailment credit minus any noncompliance charges?

MR. CONWAY: Excuse me, can I have that question reread also?

EXAMINER BOJKO: And for the record, I

believe the tariff schedule we're referencing is the
energy price curtailable service rider.

MR. SETTINERI: That's correct, your
Honor.

EXAMINER BOJKO: Could you reread the
question, please?

(Record read.)

A. As I'm looking at it, that, to me, is primarily -- that change is really a language change. Previously it said less any charges computed for failure to curtail, and there were charges for failure to curtail in the existing agreement.

The way I look at this, it's now we're calling them noncompliance charges, and the calculation I think was changed in the next provision a little bit so there were -- so I guess I'm struggling with that actually being the change. I think the change was really in the next section.

Q. Well, regarding the noncompliance charge, that's the charge assessed against a customer who fails to comply with a request for a curtailment, correct?

A. And I think we actually have to jump two tiers back or one tier back to answer that really. One of the changes within the price curtailable

service rider was that previously when the company
requested a curtailment under this rider, the
customer didn't have a choice to say yes, I want to
participate this time, or no, I don't.

One of the changes to make this rider
more attractive was to give them the option to have a

few times where they could say, boy, that's really a bad time for me. I'm in the middle of a process run, or whatever else, and I really don't want to participate at this time.

And so kind of in that next section under Failure to Curtail, if the customer responds affirmatively that it will participate in a curtailment event, so first they now have to say "yes, you notified me, I'm willing to participate," and then if they say "yes, you notified me, I'm willing to participate" and then they don't actually reduce, even though they said they were going to, then the noncompliance charge would apply.

Q. And that charge is equal to the cost of the energy the customer failed to curtail during the event; is that correct?

A. It would be the amount of energy that they failed to curtail in each hour of the event, and it would be multiplied by the curtailment credit for

each hour, so it would be the same rate that they
would have been paid for the curtailment.

Q. So I understand, a customer who fails to comply under the PCS rider would not only pay for the energy used during the requested curtailment event, but also pay a charge equal to the amount of energy

they failed to curtail, correct?
A. I believe that, but let's be clear on how you're saying that. The customer on the price curtailable service rider is also on some firm service tariff. All energy that they use will be billed under the firm service tariff. To the extent they commit to reducing energy and then fail to do so, then there will be a noncompliance charge at the rate that they would have received had they reduced that usage.
Q. Okay. In fact, if a customer -- if the amount of the curtailment credits a customer would receive a month is less than the noncompliance charges, wouldn't that customer have to pay the companies the difference?
A. Under your hypothetical, yes, they could. And in my mind that's a customer who's, one, not doing what they said they were going to do, and two, not behaving economically rational.

EXAMINER BOJKO: Mr. Roush, could you talk in the microphone a little more or pull it closer.

THE WITNESS: I'm sorry.

EXAMINER BOJKO: Do you need the answer reread?

MR. RANDAZZO: No.
You're trailing off.
THE WITNESS: I'm sorry.
MR. RANDAZZO: Thank you.
THE WITNESS: That's why I don't do karaoke.
Q. (By Mr. Settineri) Mr. Roush, isn't it true that AEP has not conducted any studies comparing the demand response programs offered by PJM to the demand response programs proposed by the companies?
A. We have not done any studies to compare the two programs, no.
Q. Again, you are familiar with the PJM demand response programs in general, correct?
A. Yes, I am.
Q. And are you familiar with the PJM emergency capacity programs?
A. The emergency capacity only or emergency full or both?

Q. Both.

A. Yes.

Q. This would include the PJM ILR demand response program, correct?

A. Yes, it would.

Q. Isn't it true that in your opinion the

PJM emergency capacity programs are very attractive to customers when compared to the companies' interruptible service offerings?

THE WITNESS: Would you mind reading that one back.

(Record read.)

A. Yes, I would agree with that statement. And here's why, it's because under the PJM capacity programs, to the extent -- since the company has been a member of PJM, PJM has never asked a customer in PJM's -- in AEP's zone to curtail under those programs, so they're very attractive from the standpoint that the customer gets credits through PJM that has yet to have to do anything.

Q. Mr. Roush, those customers that you just referenced that have not curtailed under the PJM demand response programs in the AEP zone, is that a guarantee that it will not happen tomorrow?

A. I'm sorry, I lost the last couple words.

Is that a guarantee -- I missed --

Q. That under the customers in the AEP zone who have not curtailed and are participating in PJM demand response programs, could a curtailment occur tomorrow?

A. Curtailment could occur tomorrow. I

would view that as highly unlikely, but you're absolutely correct in that historical performance does not predict future outcomes.

Q. Mr. Roush, on page 6 of your testimony, lines 19 through 21, you state that: "A unique aspect of the PJM programs is that unregulated entities known in PJM as curtailment service providers can solicit retail customers directly and enroll them in the PJM wholesale program." Do you see that?

A. Yes, I do.

Q. Now, are you aware that curtailment service providers can enter into long-term contracts with retail customers for participation in PJM demand response programs?

A. I guess I'm not sure. I don't know what types of agreements curtailment service providers might be entering with customers.

Q. Assume for me that long-term contracts

exist, and assume for me that the company's proposal
to ban retail customer participation in PJM demand
response programs is approved. Under that scenario
won't that ban on the PJM demand response programs
have an impact on long-term contracts?
       A.   I guess I'm struggling with the premise

to the hypothetical in that a curtailment service provider entered into a long-term contract with a customer. Personally, I think that was -- that would be an ill-advised action. You know, the company's position concerning PJM demand response programs has been well documented, well known for at least four years, and further, you know, the Commission itself here in Ohio has also taken the position that they have a role in retail demand response as recently -- even the recent NOPR, FERC NOPR, N-O-P-R, so I'm struggling with the premise of the hypothetical. If someone had done that, it was in my mind not a very prudent thing to do.

MR. RANDAZZO: I object. Move to strike, nonresponsive.

EXAMINER BOJKO: Sustained.

MR. CONWAY: Your Honor --

EXAMINER BOJKO: He did not answer the question, Mr. Conway. He needs to. If he doesn't believe in the hypothetical, then he needs to answer that he can't respond. He cannot go on to say what he just said. It's stricken.

THE WITNESS: Could you reread the question, please?

(Record read.)

MR. CONWAY: Objection.

EXAMINER BOJKO: Grounds?

MR. CONWAY: I think that he previously answered when the question was asked before that he had a hard time with the assumption, so that the hypothetical was not a legitimate one from his point of view.

EXAMINER BOJKO: Well, if the witness believes that, then the witness should say that and finish his answer. He should not continue on as he did the last time.

So if you can answer the question based on the hypothetical posed, Mr. Roush, please do, and do not elaborate on your opinions of whether something is possible or not.

A. I guess I'm having trouble agreeing with the hypothetical.

Q. Mr. Roush, are you familiar with how payments to customers participating in the PJM demand response programs are funded?

A. Generally, yes.

Q. And are you familiar with how payments to customers participating in the PJM ILR program are funded?

A. Generally, yes.

Q. Isn't it true that in the ILR program payments to customers come from the RMP market clearing, which means that it comes from all the load-serving entities who have to buy their capacity in the RPM market?

THE WITNESS: Could you read that one back, please?

(Record read.)

A. Yes, that is the way PJM gets the money to pay ILR customers.

Q. Mr. Roush, isn't it true that this includes load-serving entities outside of Ohio?

A. Yes, the RPM markets includes entities outside of Ohio.

Q. That would not include the companies, correct?

A. I'm sorry, I don't understand that question.

Q. No problem. Let me just jump ahead.

The companies meet their capacity
obligations as a fixed resource requirement entity,
correct?

A. Yes, that's correct.

Q. As FRR entities the companies do not fund
payments made under the PJM ILR programs, correct?

THE WITNESS: Can you read that one back?

(Record read.)

A. Yes, that's correct, with one caveat, just to be clear. To the extent that the company utilizes interruptible resources, we would submit them in the ILR program and use them to meet our FRR capacity obligation, just to be clear.

MR. RANDAZZO: Could I have that answer read back?

(Record read.)

MR. RANDAZZO: Thank you.

Q. Mr. Roush, how does the company use those offerings to meet its FRR capacity obligation?

A. The company uses its existing interruptible agreements, including the customers under schedule IRP-D. Those are -- that amount of interruptible capability is provided to PJM to meet our -- as part of our resources used to meet our FRR obligation, and the way that PJM has asked us to do that is to submit those loads through the PJM ILR program.

Q. And this would be loads capable of reduction, correct?

MR. CONWAY: Could I have that question reread, please?

(Record read.)

A. Yes, those would be loads that the company can request reductions from that would comply with PJM's requirements.

Q. So by offering that interruptible capacity to PJM to satisfy the FRR capacity obligation, doesn't that free up capacity for the companies to sell?

A. It only would if your premise were that this was new additional interruptible capability that the company did not already have and to the extent that that was capability associated with load that was currently firm.

Q. Does Ohio Power -- strike that.

Let me follow up, Mr. Roush. In other words, the companies can reduce their FRR capacity commitment by the amount of interruptible service offerings enrolled in PJM demand response programs; is that correct?

THE WITNESS: Would you mind reading that
back?

(Record read.)

A. Not exactly. Really what the company can do is utilize interruptible capability, utilize interruptible capability to meet its FRR capacity obligation. And it's not all PJM demand response programs; it's specifically within this ILR program.

Q. Mr. Roush, isn't it true that although the companies are meeting their PJM capacity requirements as FRR entities, the companies can still sell excess capacity in the PJM market?

MR. CONWAY: Could you read that question back for me, please?

(Record read.)

A. The companies can sell up to a restricted amount of capacity into the PJM RPM market, and I believe the restriction is somewhere around 1,300 megawatts.

Q. Does that restriction apply at an aggregate level or individually to each company?

A. I believe it's on an aggregate level.

Q. Okay. And when you say "aggregate," would that include operating companies outside of Ohio?

A. It would basically include the AEP East
operating companies.

Q. Okay. And isn't it true that revenue
from those sales is shared among all the generation
in AEP operating companies on a member load ratio
basis?

A. I believe that's correct.

Q. All right. In some states that revenue would flow to the operating companies' shareholders, correct?

A. I guess it depends. There are lots of assumptions underlying that. The revenues from capacity sales into the RPM market would flow into whatever rate-making paradigm existed, so, for example, if that was -- if those were considered off-system sales margins, they may be shared between the shareholders and the customer. They may be just another revenue of the company that's contemplated each time a base rate proceeding occurs. There's just any number of possibilities.

Q. Mr. Roush, my question was pretty simple, I just want to know in some states isn't it true that revenue would flow to the operating companies' shareholders --

MR. CONWAY: Objection.

Q. -- is that correct? Some states.

MR. CONWAY: He said it wasn't a simple question and he answered it completely.

MR. SETTINERI: Your Honor, I don't believe the answer was responsive. I believe the question was very straightforward.

MR. CONWAY: He said there were various treatments. It depends on the regulatory regime applicable, which varies from state to state.

EXAMINER BOJKO: Okay.

MR. SETTINERI: Your Honor, my question was --

EXAMINER BOJKO: I know the question. I know both sides. I believe Mr. Roush answered it to his ability. I don't think he's going to answer it any differently no matter how many times we ask it, so sustained.

Q. (By Mr. Settineri) Mr. Roush, am I correct that you believe an Ohio revenue would accrue to shareholders of Ohio Power and Columbus Southern Power?

MR. CONWAY: I'm sorry, could I have that question reread again?

(Record read.)

MR. CONWAY: I'll give you -- I would

offer a light objection, which is what revenues are
we talking about?

EXAMINER BOJKO: I don't understand the
question there.

MR. SETTINERI: I'm sorry, back up.

Q. Going back to, Mr. Roush, we discussed earlier about the companies' ability to sell excess capacity in the PJM market, and you testified that revenue from those sales is shared among the generation companies of AEP East. What I'd like to know is, and I guess the question here is, am I correct that you believe that in Ohio that revenue -- that revenue would accrue to shareholders of Ohio Power and Columbus Southern Power?

MR. CONWAY: And I'll offer another light objection, which is that he referred to margins, not revenues in his answers, and you've now substituted "revenues" for what he provided to you.

EXAMINER BOJKO: Mr. Roush, please answer the question if you can. I'm sure you'll clarify for us your response.

THE WITNESS: And I apologize, would you mind reading it back?

(Record read.)

A. In the context of the companies' ESP, as

I understand it, the margins from off-system sales would not be part of the significantly excessive earnings test. To the extent that those margins might include revenue from capacity sales, then those dollars would accrue to shareholders under the companies' ESP.

Q. Mr. Roush, if you could turn to page 72 of 285 of Exhibit DMR-9, please.

A. Okay. I'm there.

Q. Now, isn't it true that a retail customer taking service under schedule GS-4 pays a minimum charge for capacity?

A. I guess I'm struggling with that question. There is a minimum charge provision under schedule GS-4. It's not specific whether they're paying for capacity, energy, or what. It's service.

Q. Well, on this page can you point out to me the energy charge?

A. Sure. The energy charge for schedule GS-4 in total is 0.09058 cents per kilowatt-hour.

Q. What about the demand charge right above?

A. It's a block demand charge. The first 3,000 kVA are $10.997 per kVA. Any kVA over 3,000 kVA are $5.053 per kVA.

Q. Is that a capacity charge, Mr. Roush?

A. I guess that's where we're having the disconnect. In my mind, it's a demand charge. It's not the same exact nature as the capacity charge as we've been talking about in the PJM market.

Q. Okay. Let me make it a little easier. A customer under that schedule will pay that charge regardless of whether the customer participates in the PJM demand response program, correct?

A. A firm service customer would pay these rates.

Q. Okay.

MR. RANDAZZO: Could I have the answer read back?

(Record read.)

EXAMINER BOJKO: Did you say yes, affirmative? I think you nodded your head.

THE WITNESS: I'm sorry. Yes, a firm service customer would pay these rates.

Q. Mr. Roush, isn't it true that in the event of a curtailment by an Ohio customer taking a standard service offer from the companies, that the companies could then sell that energy in the realtime market?

THE WITNESS: Could you read that one back? I'm sorry.

(Record read.)

A. I think this goes back to a previous question where I said I can't necessarily agree to that. It could either be that the company had additional energy to sell as a result of the curtailment or they could avoid a purchase.

Q. Okay. Let me make it specific, that in the event of a curtailment under the PJM ILR program.

A. Unfortunately, I have to give you an "it depends." It depends on which flavor of the ILR program they've chosen. If they've chosen the capacity-only version, then that would -- versus the capacity and energy or the emergency full program version, under the emergency full program version the customer I believe would be selling the energy to PJM. It would be effectively selling the energy to PJM.

Under the capacity-only version, again, it goes back to my previous answer of that would either allow the company to make a sale of that energy or reduce the purchase for the company.

Q. Mr. Roush, are you aware that Dayton Power & Light has filed an application for an electric stabilization plan?

A. Yeah, I'm aware that they filed one.

That's about the extent of my knowledge of it,
though.

Q. All right. And so let me ask the
question regardless, are you aware that DP&L did not
ask for a ban on PJM demand response programs in the
application?

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481

A. I am not aware one way or the other.

Q. Well, assume for me that that is the case, that the application does not include a request for a ban on PJM demand response programs, and assume that the company's ban on PJM demand response program participation is approved. Wouldn't that result in different treatment of Ohio customers within the PJM zone in Ohio?

MR. CONWAY: Objection. He said he's not aware of what's in the Dayton Power & Light -- he is not aware of what's in the Dayton Power & Light application. We don't have the application in front of us, and there's no basis for going forward with the hypothetical.

EXAMINER BOJKO: I would agree with you to where I thought the question was going, but where the question ended up I think that Mr. Roush can answer if that would occur, his -- if he has an opinion, he can answer.

MR. CONWAY: Could you reread the
question for u please?

THE WITNESS: Thank you.

(Record read.)

MR. CONWAY: And we're also assuming --
excuse me. We're also assuming that the Commission

has not weighed in on the issue, the Ohio Commission.

MR. SETTINERI: In this scenario --

MR. CONWAY: And that the Ohio Commission is allowing differential treatments.

EXAMINER BOJKO: Regardless -- it has nothing to do with Dayton's application. Can you rephrase your question, it has nothing to do with Dayton's application.

MR. SETTINERI: Right.

Q. (By Mr. Settineri) Mr. Roush, assume that the company's ban is approved and that ban is a ban on the PJM demand response participation, and assume that there is no other ban in Ohio on PJM demand response participation by any other EDU except for the companies. Under that scenario wouldn't there be different treatment of Ohio customers as to participation in the PJM demand response programs?

A. I think that based upon the hypothetical you laid out, it's kind of like one plus one equals two.

Q. Is that a "yes?"

A. Assuming your hypothetical, then the answer has to be your conclusion, which is yes.

Q. Mr. Roush, at page 6, line 1 of your testimony, you state that: "The Companies should be able to count the load that is capable of being reduced towards peak reduction goals, even if that load was not reduced at the time of peak because operational and/or market conditions did not dictate the need for reduction." Correct?

A. Yes, that's correct.

Q. All right.

MR. CONWAY: Mr. Settineri, just so the record's clear, at this point you're not discussing aspects of the PJM demand response program and the company's position regarding participation of customers in that program, but rather you've moved on to a different topic, I believe.

EXAMINER BOJKO: Mr. Conway, let him ask his question. Right now he just asked on page 6 whether that statement was on the record. Let him ask another question.

Q. Mr. Roush, do you believe that the companies should be able to count the load that is capable of being reduced in a PJM demand response program towards the companies' peak reduction goals?

THE WITNESS: Can you read that one back, I'm sorry.

(Record read.)

A. I'm not sure. Looking at my testimony, specifically what I said on page 6 is that: "The Companies should be able to count load that is capable of being reduced toward peak reduction goals, even if that load is not reduced at the time of peak because of operational and/or market conditions did not dictate the need for reduction."

I'm just not sure -- I'm not sure that links up with the clause you put in your question, which was "for PJM demand response programs." The language I was laying out here was interruption, you know, was interruptible capability that was available for the company to exercise that interruption.

Q. Mr. Roush, going to the next step, do you believe, though, that the PJM -- load that is committed to PJM demand response programs can also -- should also count towards the company's peak reduction goals under Senate Bill 221?

A. I guess that's the part where I'm not sure.

Q. Do you have an opinion?

MR. CONWAY: Objection.

EXAMINER BOJKO: Sustained.

Let's go off the record for a minute.

(Discussion off the record.)

EXAMINER BOJKO: Let's go back on the

record.

Q. Mr. Roush, earlier you noted that there was currently a limit that applies to the company's capacity commitment as FRRs to the PJM. Do you recall that?

A. I recall saying there's a limit on the amount of capacity the company could sell into the RPM market.

Q. That's correct, thank you.

A. Yes.

Q. Am I correct that AEP has proposed raising that limit to the PJM working group?

A. I believe that's correct.

MR. SETTINERI: Thank you. No further questions, your Honor. Thank you.

EXAMINER BOJKO: Let's go off the record.

(Discussion off the record.)

(At 12:00 p.m. a lunch recess was taken until 1:05 p.m.)

- - -

Monday Afternoon Session,
December 1, 2008.

- - -

EXAMINER BOJKO: You're still under oath.

THE WITNESS: Yes, your Honor.

EXAMINER BOJKO: Let's go back on the record.

Yes, Mr. Settineri.

MR. SETTINERI: Your Honor, if I may. I'd just like to go ahead prior to moving on to the next cross to move to admit Integrys Exhibit No. 3 in the record at this time.

EXAMINER BOJKO: Any objection?

MR. CONWAY: No objection. I was going to recommend we just wait and do them all at the same time, but whatever the preference is.

EXAMINER BOJKO: Let's go ahead and do it now since he's already moved.

Hearing no objections, Integrys Exhibit 3 will be admitted.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER BOJKO: OCC, I'm sorry, I forget who stated was going to do the cross-examination.

MS. GRADY: I will be crossing Mr. Roush.

EXAMINER BOJKO: Ms. Grady, please

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481

proceed.

MS. GRADY: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Ms. Grady:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. I'm going to start with a little bit of follow-up questions from the prior counsel, Mr. Settineri, and I want to focus on Integrys Exhibit No. 3, the discretionary interruptions that occurred from 2006 through 2008. Do you have that document?

A. Yes, I do.

Q. Could you tell me, Mr. Roush, if these interruptions could then be turned into off-system sales?

EXAMINER BOJKO: Did you say "could"?

MS. GRADY: "Could," yes.

Q. Could have been during that same time frame turned into off-system sales. Is that what would happen, if you know?

A. It could be one of two things. One, it could have allowed the company to avoid a purchase; the other would be that it could allow the company to make an additional sale. Those are the two possibilities that generally occur with these types of interruptions.

Q. And when you said to make an additional sale, you were talking about an off-system sale; is that correct?

A. I guess ultimately potentially yes, it could be an off-system sale. It could also just be an intercompany sale potentially.

Q. Now, in the event -- let's take, you mentioned, well, actually three options that these interruptions -- that could result from the interruptions. Let's assume that the discretionary interruptions shown on Integrys No. 3 allowed off-system sales for the moment.

Do you know, Mr. Roush, you would price those off-system sales, whether they would then be priced at the interruptible rate or whether or not they would then be priced at some other price?

A. I guess the hypothetical we're working on here is we, the company, issues a discretionary interruption request.

Q. Yes.

A. The customer elects to reduce load instead of pay the replacement electricity price.

Q. Yes, which would be what is shown on this Integrys Exhibit No. 3. Those are the discretionary interruptions, correct?

A. Integrys Exhibit 3 shows the discretionary interruptions, yes, that's correct. I'm just trying to follow your hypothetical. So the company requests the discretionary interruption. The customer elects not to purchase replacement electricity but chooses to reduce load, and under the assumption that that resulted in an additional sale --

Q. Yes.

A. -- by the company, I would believe that that additional sale would generally occur at whatever that prevailing hourly market price was at the time.

Q. So it would not necessarily be tied to the interruptible power that the sale evolves from?

A. I'm not sure I'm understanding your

question. I think it would generally be pretty close
to the price that the replacement electricity was
quoted to the interruptible customer. So if the
customer had chosen to buy through instead of reduce
load, it should be pretty close to that same price.
Q. And the price terms, those are controlled

by the interruptible tariff that the customer would have been under if the interruptible customer would have been -- if the load would have been priced to that interruptible customer?

A. The quoted price for replacement electricity --

Q. Yes.

A. -- that whole provision is within the interruptible tariff construct, yes.

Q. Thank you.

Now, you were asked a number of questions about the PJM demand response programs, and I want to follow up on some of those questions. Can you tell me, does AEP participate in PJM's demand response energy programs, if you know?

A. There's never an easy answer when it comes to PJM programs, I'm sorry. The interruptible customers like the Ohio IRP-D customers that we submit into the ILR program, I believe that enrollment is under the full emergency program, which does have an energy component. We don't request payments for the energy under those subscriptions, so even though that's the way they're enrolled, we do not request energy payments.

So other than that, no, no, we do not

participate in the energy . . .

Q. Do you receive any energy payments under those programs?

A. We don't receive any payments at all under those.

Q. Does AEP participate in the PJM demand response capacity programs, if you know?

A. That goes back to that same item. The ILR, which we submit under the emergency full program, the main reason we're doing that is the capacity to use that -- be able to use that capacity in the FRR obligation.

So that is the way we participate in the capacity programs. We don't receive payments from PJM. All we -- we have to submit it that way to get credit for it to count towards our FRR capacity obligation.

Q. Would it be safe to assume, Mr. Roush, that you do not -- AEP does not participate in any

demand response programs that are offered by PJM,
except for the emergency program that you've been
discussing?

A. Except for the emergency program that
we've been discussing, yes, and there's really no
reason for us to. If one of our customers reduces

load, our load obligation goes down so we avoid having to pay ILP for that load so there's no reason to submit it into the program.

Q. Now let's go to your testimony, Mr. Roush, and I'm going to focus on page 2, lines 18 through 22, and your testimony then carries over to page 3 and you explain what the purpose of your testimony is, and you explain that -- you summarize the company's requested rate increase and you also explain the design of the company's proposed rates and riders. Do you see that?

A. Generally, yes. Yeah.

Q. And you provide the rate impacts on the company's customers associated with those proposed rates in your testimony, correct?

A. Yes.

Q. Now, if I wanted to see a summary of the requested rate increase, I would go then to your schedule DMR-1?

A. Yes, that's correct.

Q. Let's go there for a moment, if you will. DMR-1 of 2 would be the CSP summary requested rate increase and Ohio Power would be DMR-1 page 2 of 2; is that correct?

A. Yes, that's correct.

Q. And let's begin with DMR-1, page 1 of 2, the Columbus Southern Power Company schedule. If I looked at the FAC component, the first line, and I see the first column entitled Current Rates, those, Mr. Roush, would be -- the values in the Current Rate column would reflect the current rates supplied to 2009 forecasted usage; is that correct?

A. Yes, the Current Rate column is current rates applied to forecasted 2009 usage.

Q. And the entire year -- the entire 2009 is forecasted usage; is that correct?

A. Yes, 2009 is fully forecasted.

Q. And do you know, Mr. Roush, if that forecasted usage has been updated?

A. Yes, I believe it has. The values I used were based upon the forecast that was on file with the Commission. I believe Mr. Nelson testified that he used a more recent forecast.

Q. But Mr. Nelson did not present the

summary of the requested rate increase, correct?
And, therefore, any forecast was not built into the
company's ESP proposal; isn't that correct?

A. Could you split those up for me? I'm
sorry, I got lost, rather than have her reread it.

Q. Let me rephrase, then. You indicated

that Mr. Nelson presented forecasted information
different than the 2009 current forecast. Let me
strike that.
            Can you tell me what you indicated
Mr. Nelson did with the forecast?
       A.   My recollection is in discussing the pro
forma schedules that the company provided subsequent
to its original filing, that Mr. Nelson said a more
recent load forecast was used in preparing those.
       Q.   I'm sorry, I didn't mean to interrupt
you. Now I'm following you. Mr. Nelson was talking
about the pro forma material that was provided in
response to -- or, in the October 16th, 2008,
filing which was introduced as OCC Exhibit 4; is that
correct?
       A.   I think so, but I don't remember what
Exhibit No. 4 was at all.
       Q.   I guess my point is, is that update to
the forecast had no impact on the ESP numbers

presented to the Commission; isn't that correct? You
were testifying -- you are showing the summary of the
requested rate increase and you are basing it on the
2009 forecast, not any updated forecast that
Mr. Nelson referred to and has incorporated in the
pro formas.

A. That's correct. My July 31st exhibits are based upon the forecast I had at that time. I have not updated these exhibits for the forecast -- for a subsequent forecast. To my knowledge, the forecast, you know, they're always updated on an ongoing-type basis, and I believe the differences were not material.

Q. Do you know -- did you do that comparison, Mr. Roush, to look at the forecasted usage, what was reflected in your DMR-1, did you look at the 2009 forecasted usage and compare that to the actual usage?

A. No. That's not possible. What I did look at was the 2009 forecast that I had and used in my Exhibit 1 versus the updated 2009 forecast, and the updated 2009 forecast showed, I think, ever so slightly lower forecast kilowatt-hours than the one I used.

Q. And do you know whether that forecast was ever presented by the company for purposes of this proceeding in calculating the ESP rate proposal?

A. I'm sorry, which forecast?

Q. The update to the 2009.

A. I don't know.

Q. Now, the current rate, the source of the current rates would be Mr. Nelson; is that correct?

A. Which current rates? Are you specifically referencing the FAC component?

Q. Yes.

A. The current FAC component, the value in dollars per megawatt-hour would have been given to me by Mr. Nelson.

Q. And do you know whether that is contained specifically in Mr. Nelson's testimony?

A. I believe they're in his Exhibits PJN-1 and PJN-4.

Q. Would the non-FAC subtotal also be contained within Mr. Nelson's testimony, if you know?

A. No, it would not.

Q. And what would have been the source for that? Would that be Mr. Baker's testimony?

A. No. It would not. It would have been my testimony.

Q. The source of the POLR number, where

would that -- who would that be?
A. Again, just to be clear, we're focusing on the Current Rates column?
Q. Current Rates column, I'm sorry, yes.
A. That would be me.
Q. Okay. And the source for the

distribution current rates?

A. That would also be in my workpapers.

Q. The transmission cost recovery source, is that contained in your testimony?

A. Yes, also within my workpapers.

Q. Now, Mr. Roush, the TCR, does it count toward the 15 percent cap?

A. That is not in my testimony. It's in Mr. Baker's testimony. But my recollection is that any changes in the transmission cost recovery rider are not part of the consideration in the approximate 15 percent cap.

Q. Now, if I looked at the column entitled FAC Increase for 2009 and I see the $147 million, that equates, does it not, to Mr. Assante's schedule LVA-1, the base FAC revenues collected; is that correct?

A. I don't have Exhibit LVA-1 in front of me, but I believe Mr. Assante would have used my number in preparing that.

MS. GRADY: May I approach the witness,
your Honor?

EXAMINER BOJKO: You may.

MS. GRADY: Actually, if counsel for the
company could provide Mr. Roush with a copy of

Mr. Assante's schedule LVA-1, page 1 of 1, I would appreciate it, because I have a couple of questions to tie the numbers between the two schedules.

Q. So, Mr. Roush, the numbers shown -- the DMR-1, page 1 of 2, the FAC increase number for 2009, the 147,939,677, that equates to the line entitled deferred FAC -- I'm sorry, Base FAC Revenues Collected of 148 million for 2009 shown under LVA-1?

MR. CONWAY: Excuse me, I wasn't quite able to keep up with you, counsel. As you went from LVA-1, were you --

MS. GRADY: Yes.

Q. LVA-1, if we go to LVA-1 for 2009, we see an item called Base FAC Revenues Collected of $148 million. My question, Mr. Roush, is that what you were indicating under 2009 for FAC increase on your DMR-1, page 1 of 2?

A. Yes. Those numbers should tie, and just to be clear, the number on my exhibit is 147,939,677.

Q. Yes. Now, Mr. Assante shows on his
schedule LVA-1 $112 million of deferred FAC expense.
Is there anything on your schedule which would show
the deferred FAC expense for 2009?
A. Not on my Exhibit DMR-1. You could
derive it from the values shown on Exhibit DMR-7, but

I believe the calculation was also done in a workpaper that was provided in this case.

EXAMINER BOJKO: I'm sorry, whose workpaper, yours or Mr. Assante's?

THE WITNESS: It was my workpaper.

Q. Do you know who that would have been provided to? Did you provide that to OCC?

A. It was provided in discovery. I'm thinking it was OEG request 1-9, if I remember correctly.

Q. Thank you.

Now, is it your understanding, Mr. Roush, that the deferrals are of the FAC costs first or solely? In other words, is there anything being deferred other than the fuel adjustment costs under the proposal of the company?

A. If I remember correctly, there are some deferrals related to line extensions. I'm trying to think. I don't recall. There may be some others, but probably better for Mr. Assante.

Q. Now, if we look at 2010 on your schedule DMR-1, we see for environmental capital investment for 2010 that there is a zero amount listed. Would that reflect there is no incremental capital investment for environmental expenditures but that the $26 million that are shown for 2009 carries through in the rates for 2010 as well as 2011?

MR. BELL: May I have that question read over.

EXAMINER BOJKO: You may.

(Record read.)

Q. And that would be revenues from environmental capital investment.

MR. CONWAY: Excuse me, I don't want to make an objection, but are you referring to the line on the DMR-1 page 1 of 1 which is entitled "Non-FAC Components 2001 through 2008, Incremental Environmental Capital Investment"?

MS. GRADY: Yes. Yes.

A. What I'm showing there is that there is an increase that happens in 2009 of 26 million.

Q. Yes.

A. There's no further increase in 2010 or 2011 related to the 2001 to 2008 incremental environmental capital investment.

Q. But the way the plan works, the $26 million in rates then gets carried forward in 2010 and 2011.

A. Yes. The way I've presented this exhibit is you start with current rates, show the increase

that happens in 2009, show any additional increase
that happens in 2010, and then any additional
increase that happens in '11.

Q. Thank you. Now, for 2010 and 2011 you
show the maximum FAC increase, and if we look at
2010, you show $247 million. Do you see that?

A. Yes, I do.

Q. And that maximum increase reflects the 15
percent cap; is that correct? That's how you
determined what the maximum could be?

A. Yes. I determined the 247 million value
by applying the approximate 15 percent cap and
backing out all of the other increases, so it was
purely a backed-into number.

Q. And we can see that the fuel portion of
the increase is the majority of the increase, in
fact, 12.28 percent of the 15 percent increase
relates to fuel; isn't that true?

A. That's true. And all I was trying to do there is really just lay out the most under the company's ESP that the FAC could increase in 2010, not make any projection of what 2010 FAC might actually be. So really that portion is not a forecast of FAC at all.

Q. I understand now. Did the company,

though, actually present a forecast of the FAC
expense that it expects in 2010 and 2011?

A. I believe that was provided as part of
the pro formas that were filed on October 16th.

Q. And are you --

A. Or the workpapers to it, I'm not sure
which.

Q. Yes. And are you familiar with that
forecast, the workpapers that actually are behind the
financial information filed?

A. Actually, I have not looked at them.

EXAMINER BOJKO: I'm sorry, I thought you
said you did look at Mr. Nelson's FAC forecast and
determined that it was -- determined what the
difference was.

THE WITNESS: I looked at the load
forecast. I didn't look at these workpapers.

EXAMINER BOJKO: Okay.

THE WITNESS: So you are correct, I did

look at the load forecast.

Q. Let's go to page 4 of your testimony. In lines 8 through 11 you discuss that: "Exhibit DMR-1 does not show any estimate of the potential increase resulting from the Economic Development Cost Recovery Rider." And I want to focus on that portion of your statement. Now, the cost of economic development collected under the rider will be based on a number of factors; isn't that correct?

A. Yes. The amounts were based upon whether the Commission first approves any such agreements and then will be based upon whatever the usage of the customers under those agreements are and the terms of those agreements.

Q. So the actual usage of the customers would impact it, as well as the amount of incentives that they receive during the ESP?

A. Yes, both of those would be factors.

Q. And also whether there's a sharing of the delta revenues, that would impact the cost of the economic development collected under the rider?

A. Under the company's proposed ESP there's no sharing of the delta revenues.

Q. But if there is a sharing of the delta revenues imposed by the Commission, would that impact

the cost of the economic development collected under
the rider?

A. Assuming there were a sharing mechanism,
that would impact the amounts collected under the
rider.

Q. The company has not estimated at this

time, has it, the costs that would be collected under
this rider?
A. No, it has not.
Q. Now, with respect to the transmission
cost recovery rider, you also indicate that DMR-1
does not show an estimate of any future changes in
the level of the company's existing transmission cost
recovery rider. Do you see that?
A. Yes, I do.
Q. The company has not made an estimate of
any future changes at this point in time with respect
to the level of the TCR?
A. No; that's not correct. At the time of
the preparation of the company's ESP, we had not made
a transmission cost recovery rider filing. Those are
generally made in late-October of each year. We have
since filed I think October 31st for the 2009
transmission cost recovery rider and I believe it's a
decrease for one of the companies and an increase for

the other.

Q. Has the company proposed to update its ESP to reflect that recent filing to change the rider, if you know?

A. Not to my knowledge, nor is there a need to.

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481

Q. And why is there not a need to?

A. I believe, as we discussed earlier, the only reason there would be, would be if we were considering the TCRR as part of the approximate 15 percent cap, and since my recollection of Mr. Baker's testimony is that that's not part of that consideration, there's no reason to.

Q. But it is a cost to the customer, is it not, to the consumer, the TCR, and the customers should be charged the current TCR; isn't that correct?

A. That's absolutely correct. And as I mentioned earlier, I believe it's a decrease for one of the companies.

Q. So how would the ESP reflect that decrease, or is it just a decrease that's dealt with outside of the ESP?

A. Well, this probably gets a little potato-potato. The company's ESP proposes to

continue operation of the transmission cost recovery
rider, which I think I discuss later in my testimony
on page 11, beginning at lines 11 through 22. So
because we're proposing to continue operation of the
transmission cost recovery rider, you can say it's in
the ESP, or you could say since it's continuing to

operate, it's outside the ESP. That's why I see it as potato-potato.

Q. If a customer wanted to know the impact of the ESP rates on their bill, wanted to know what it's going to cost, they would have to know the cost of the TCR rider as well, and I guess my question is how would you fold that into the ESP process and make customers aware of the total impact of the ESP, including the TCR rider?

A. I guess I'm struggling with it as the TCRR has been changing annually for a while and the company's rates changed annually under the RSP as well, so, I mean, I think we'll do the same type of communication that we've done in the past as far as customers rates are changing.

EXAMINER BOJKO: So it operates -- the TCR rider would operate independent of the ESP, just like it has been, or independent of the RSP.

THE WITNESS: Yes, I'd agree with that.

Q. Now, on page 6, lines 1 through 4, you
talked about -- and Mr. Settineri began to get into
this with you. You talk about being "able to count
load that you're capable of reducing toward peak
reduction goals, even if the load was not reduced at
the time of peak." Do you see that reference?

A. Yes, I do.

Q. Now, the peak reduction goals you're talking about are the goals under SB 221.

A. Yes, that's correct.

Q. Is there language in SB 221 that would suggest that your proposal to count capable load versus actual interrupted load as being construed to -- as being construed to peak reduction under the statute?

MR. CONWAY: Could I have that reread, please?

EXAMINER BOJKO: Please.

(Record read.)

MS. GRADY: Let me rephrase. I will try to rephrase that.

Q. Is there language in 221 that supports your view that load that is capable of being reduced versus load that is actually reduced should count toward peak reduction goals?

A. Based upon my reading of the legislation,
which I'm not a lawyer, obviously, it doesn't seem to
be terribly specific. It talks about programs
designed to achieve a 1 percent reduction of peak
demand in 2009, so in my mind it's an appropriate
clarification that the company's seeking from the

Commission.

Q. But there's no specific language supporting that view that you can see as a nonlawyer.

A. From what I can see, it's not, in my mind, terribly crystal clear in the legislation.

Q. Now, when you were talking about your proposal to count load that's capable of being reduced, are you speaking of the IRP-D schedule customer load?

A. I think today specifically that load.

Q. Yes.

A. I think down the road that could include other types of load reduction type programs beyond that.

Q. Now, when you made your statement in your testimony, were you referring to the IRP-D schedule?

A. Definitely the IRP-D schedule. What I was just trying to think through is whether that might also include a customer that signs up for ECS,

but I don't believe the ECS would count because the
customer isn't obligated to reduce load.

Q. Now, are there two provisions under the IRP-D schedule, one for mandatory curtailment and then an additional one where customers are offered the option to purchase replacement, or am I mixing

apples and oranges here?
A. If you look at Exhibit DMR-9, page 75 and 76, that's kind of where it lays out the two different types of interruption conditions. The first type are the discretionary interruptions, and that's shown on page 75 of Exhibit DMR-9; and then the description of emergency interruptions are on page 76 of DMR-9, the description of those are there. So those are basically the two types of interruptions under IRP-D.
Q. Now, the customers under the option where the customers can purchase replacement electricity in order to operate in lieu of reducing their load, isn't it a fact that under that type of option they can -- the customer can choose to reduce some of its load and not all of it, and also can make the choice to purchase some load but not all?
A. Yes. Under the discretionary interruption provision it's not an all or nothing.

The customer can choose to purchase some or, you know, none, some, or all of its power under the replacement electricity provision; or, conversely, choose to reduce none, some, or all of it under the discretionary interruption provision.

Q. Do you know, Mr. Roush, if under SB 221 the companies already meet the peak load reduction goals in year 1 by using IRP-D schedule with the current customers?

A. I don't know that I've looked at that.

No, I don't know.

Q. Now, on page 6, lines 9 through 10, you indicate there that services previously made solely for large industrial customers will likely become effective and available to a larger group of customers. Do you see that reference?

A. Yes, I do.

Q. And there you're referring to price-responsive services like demand response; is that correct?

A. I'm just trying to not get into a vocabulary quagmire with you. I apologize. I think price-responsive tariffs could include things other than just demand response kind, in my view.

Q. Now, would you agree with me, Mr. Roush,

that with gridSMART you'll be able to expand the
demand offerings to a growing number of smaller
customers?

A. With gridSMART we could offer things such
as direct load control, which I would consider demand
response. We could offer enhanced time-of-use rate

offerings that I wouldn't necessarily consider demand response. We could also offer things like critical peak pricing potentially, and those are kind of a hybrid of the two.

Q. And ultimately you'd be able to expand these offerings to residential customers; is that what your testimony indicates?

A. With gridSMART, absolutely we'd be able to make those types of offerings to residential customers, particularly like direct load control generally is focused almost exclusively on residential.

Q. Now, I'm going to go back to DMR-1, and I want to talk to you about the annual 3 percent non-FAC increase for CSP and the 7 percent non-FAC increase for Ohio Power. These are areas which Mr. Baker testifies to; am I correct?

A. The rationale for the 3 and 7 percent increase?

Q. Yes.

A. Yes, I believe that's correct.

Q. Do you have a general understanding what makes up these annual increases?

A. Yes. My general understanding is that they're kind of nonspecific, non-FAC-related generation costs.

Q. Is it your understanding it would cover environmental capital expenditures and ongoing increases such as labor and materials?

THE WITNESS: Do you mind reading that back?

(Record read.)

A. Yes. I think those are the kinds of things that would fall into that, although I would not say it's the environmental capital expenditure but like a carrying cost on it would be more comparable.

Q. Now, moving on to the distribution rate increase, you have shown in your schedule DMR-1 a 7 percent increase for CSP and a 6.5 percent for Ohio Power; is that correct?

A. That's correct.

Q. And you indicate on page 11 of your testimony that the 7 percent increase for CSP relates solely to the reliability program and gridSMART.

A. Yes, as shown on my Exhibit DMR-4.

Q. Yes, I was just going to get there. So DMR-4 shows a breakdown of the dollars between -- for the distribution percentage increase between gridSMART and distribution reliability for CSP, and

then we also see -- is that correct?
A. Yes. Exhibit DMR-4 for CSP shows the development of the gridSMART-related dollars, the development of the distribution reliability-related dollars.
Q. And for Ohio Power we see that the dollars associated with the 6.5 percent annual increase relates solely to the enhanced reliability program, correct, not gridSMART?
A. That is correct.
Q. Now, going back to DMR-1, I want to talk to you about your POLR charges. We look at the POLR line, and we're going to start with DMR-1, page 1 of 2, which is Columbus Southern, we would see a $14.5 million POLR charge in current rates, and then for Ohio Power, if we looked at page 2 of 2, we would see that there's 39.7 million in POLR charges reflected in current rates. Do you see -- is that correct?

A. Yes, that's correct. That's the application of the current POLR rates to 2009 forecast usage.

Q. The company would be able to determine how much it's collected in 2008 in POLR revenue, would it not?

A. Not entirely yet. You could only determine up through probably October of 2008 at this point.

Q. Is it your understanding, Mr. Roush, that the current POLR revenues shown on DMR-1 under current rates, it will not be trued up to reflect the actual usage versus -- it will not be trued up to reflect actual usage, let me put it that way.

A. No, there wouldn't be a trueup. The current rates just represent the application of current rates to forecasted '09 usage.

Q. And, in fact, there wouldn't be a trueup for any of the items shown under the current rate column to show the actual usage -- to show the revenues applied to actual usage, correct?

A. I guess not exactly because if you think about how the company's proposed ESP works, the FAC would be trued up in 2009 based upon actual expenses and actual usage, and similarly, the transmission

cost recovery rider as we discussed earlier is always
trued up to actual expenses and actual --

Q. I understand. But the first column, the
Current Rates column, that is the starting point, is
it not, for future adjustments, and it is the future
adjustments that will be trued up?

A. No. Specifically with those two items, total FAC expense is trued up and total TCRR expense is trued up. For the other items, this is not unlike traditional rate-making, to a certain extent, in that you have to set -- you know, strictly in this area, you know, you have to set here's a test-year level and how much money would be produced under current rates and how much money would be produced under proposed rates.

Q. And if you treat your current rates as test-year level, your proposal is, Mr. Roush, that the current rates remain as you have shown them on your schedule and are not trued up to actual 2009 usage.

MR. CONWAY: Objection. That's been asked and answered.

EXAMINER BOJKO: Overruled.

A. Again, I think we're having a disconnect. What I'm showing on DMR-1 is the application of rates to a set of billing units for forecasted load. If you switch to Exhibit DMR-2 and Exhibit DMR-3, for example, for the distribution rates I would be adjusting the actual rate by 7 percent for that 7 percent annual increase. So I'm adjusting the rate. The 2009 usage will be whatever the 2009 usage is, but the rate itself still only went up 7 percent for that adjustment.

Q. The forecasted billing units that are reflected in DMR-1, the current rate column, are not going to be updated, are they, to reflect the actual billing units for 2009 under the ESP proposal presented by the company?

MR. CONWAY: Your Honor, I'll just raise the same objection. He explained how the projections will be trued up to actuals for the FAC and for the TCRR, and he's explained how the rates are being adjusted for the other items, and there's no -- as I understand it, there's no need to or there's no value to looking at it as if it's a tracker or it's being trued up. He says that the --

EXAMINER BOJKO: I don't think that was the question. I think the question was is the application going to be updated.

MS. GRADY: That's correct.

EXAMINER BOJKO: And I don't think the
witness has answered that question. I agree he might
have said the thing you said, but he didn't answer
the question.

THE WITNESS: If you're asking me is the
company going to update its ESP application for a new

forecast of load, the answer to that question: No.

Q. Are they going to update it for the actual load that occurs?

A. The answer to that question I think is also no. I would assume this proceeding will be ruled on and the ESP rates in effect long before actual 2009 load is known.

MR. RANDAZZO: 2008?

THE WITNESS: 2009.

Q. How about for the latest 12 months, instead of using 2009 forecasted usage in your current rate column, is the company going to update to show what is the latest known 12-month actual kWh usage?

MR. CONWAY: Objection.

EXAMINER BOJKO: Basis?

MR. CONWAY: He's already explained what the purpose of the current rates column is, and he's also explained that he's not going to be updating it for --

EXAMINER BOJKO: I think there's a misconnect. I think Ms. Grady's talking about 2008 actual known data.

MS. GRADY: The latest 12 months.

EXAMINER BOJKO: And the witness

specifically said in his response 2009.

MS. GRADY: Correct.

EXAMINER BOJKO: So it is a separate question.

MS. GRADY: Thank you, your Honor.

THE WITNESS: Could you reread the question for me, please?

(Record read.)

A. As part of its ESP application, no.

Q. Okay. So you are asking the Commission to accept the current rates as applied to 2009 forecast usage as the basis for your ESP rates; is that correct?

THE WITNESS: Can your read that one back to me?

(Record read.)

A. I'm not sure we're asking the Commission that. I think what we did in our ESP filing is present the best information we had, and the best

information we have is what will these rates that
we're asking for in this proceeding produce in 2009.
And the way that was developed was using the load
forecast for 2009, and we used historical information
that was available at that time to take that load
forecast and determine all the rate class information

and develop: Here's what would happen under current rates. Here's what would happen under the proposed ESP rates. And I think the best presentation is the 2009 forecast.

Q. Let's go to page 14. On lines 16 through 18 you testify that: "The Companies will make periodic FAC filings in accordance with the Commission's ESP rules." And there you also indicate that: "Filings will include a projection of anticipated FAC costs and will identify any current under/over recovery of actual FAC costs." Do you see that?

A. Yes, I do.

Q. Under the companies' proposal, when does overrecovery of FAC costs occur?

A. The way I look at it, after overrecovery, quote, overrecovery, would occur when, for a given period, if you looked at actual FAC expense for that period, the amounts that were deferred in that period and the amounts that were collected in that period.

So you'd say -- you'd compare your expenses on one hand during that period to a combination of your revenues and the amount deferred, and so a, quote, overrecovery would occur if a combination of the amount deferred and the amount collected, the sum of those two items exceeded the actual expenses in that period.

And I believe what would happen kind of is laid out two different places here. One, if you look at page 14, lines 6 through 9, that, quote, overrecovery would be kind of what's laid out on line 8. "Any FAC expense less than the level included in these rates will be deferred and reduce the regulatory asset."

Q. Did you misspeak? Did you mean to say "in excess than the level"? You said "less than the level."

A. Less than. I'm on line 8.

Q. I'm sorry, could you repeat that then?

A. Sure. On line 8 when it said: "Any FAC expense less than the level included in these rates will be deferred and reduce the regulatory asset."

So if we go back though that picture, you've got total FAC expense. You've got FAC

revenues and FAC deferral, and if at the end of the
day you say -- if you're in that, quote, overrecovery
position, that means you deferred too much so you'd
use that. You'd reduce the amount you deferred.
That's kind of one way of treating it.
            The other way of treating it is laid out

on lines 20 through 23, and that's kind of another way of looking at it, is now if you're looking forward in time you're saying: I'm projecting what the next period is. I believe the rules came out that said something about quarterly filings, I believe.

So if you're looking out at the next quarter and you're saying I'm projecting FAC expense to be X, and I look at that FAC expense and say that FAC expense is lower than the -- would cause an increase lower than the approximate 15 percent cap, if that happened and you already were accumulating deferrals from previous periods, you're kind of at a decision point that you could either say: Well, I'll increase the FAC a little more, still staying within that approximate 15 percent cap, and eliminate some of that deferral sooner. Or you can say: I'll just let this lower level of FAC flow through and customers will see less than a 15 percent increase.

So that's kind of a decision point that -- during those ongoing quarterly filings the Commission could make the determination what they wanted to do.

Q. Does the company have a recommendation as to what should be done, which option should be used, whether or not the regulatory asset should be reduced into the future or the -- if an overrecovery occurs, whether the FAC expense should be itself reduced in the following period?

A. At this time I don't have a recommendation. I think it's something that will somewhat depend on the circumstances at the time.

You know, if -- I'm not a big hypothetical person, but hypothetically, if you're in a situation where the economy is not doing so well, you may say: Well, rather than try to write down that deferral, let's leave that deferral go and have lower FAC in the current period. Or the flip: I just, I don't have a recommendation at this time. I think it's really going to be at the time of those quarterly filings that that decision would be made.

Q. When you use the overrecovery to reduce the regulatory asset, customers would not be seeing the benefits of that overrecovery until that

regulatory asset begins to be collected from them,
and under your proposal that would be in the years
2012 through 2018; is that correct?

MR. CONWAY: Objection. It's a compound
question. If it was one question or assumption, at
least that was not -- he didn't have an opportunity

to agree with in the first part of the compound question, and then there was a question after that.

EXAMINER BOJKO: If the witness can answer, if he can respond.

Can you respond, or do you need it?

THE WITNESS: Could you read it back at least?

(Record read.)

A. I guess I'm not totally agreeing with that because if you're reducing the regulatory asset, if you're using that amount to reduce the regulatory asset, then they're also avoiding carrying costs. So you're absolutely correct they will not see a change in their bill in that current period, but their future liability would be lower.

Q. So under that option, the customer would be paying more in the current period to reduce future payments; is that correct?

A. I guess there's a third piece of that.

The customer would be paying for more the current period to reduce future payments for past costs.

Q. Sure. Past costs being the fuel expense that's been deferred in the past, correct?

A. Fuel expense that's been deferred in the past, yes.

Q. Mr. Roush, have you seen the workpapers OCC Exhibit 6, the income statement summary for CSP? I know you said you're not familiar with it, but have you seen it?

A. I looked at the October 16th filing, I didn't look at the workpapers.

MS. GRADY: If I could ask that the company provide Mr. Roush with a copy of OCC Exhibit No. 6, I've just got one or two questions to ask him about to make sure that I'm on the same page as Mr. Roush is.

Your Honor, if you recall, Mr. Nelson was asked about this particular -- the page 1 of 12 and I'm going to pursue this. I believe he kind of punted to Mr. Roush on this so I'm going to try to pick up that.

MR. CONWAY: Your Honor, I do have one copy of OCC Exhibit 6. May I look over the witness's shoulder and share it with him while the questions are being asked?

EXAMINER BOJKO: Sure.

Q. Mr. Roush, we've been talking about --

EXAMINER BOJKO: Hold on, Ms. Grady.

I'm sorry, what is Exhibit 6?

MS. GRADY: It is the OCC request for

production 9-125.

EXAMINER BOJKO: I'm sorry, I thought we were on the Exhibit 4. Okay.

MS. GRADY: These are the workpapers that back up Exhibit 4.

EXAMINER BOJKO: Okay. Thank you.

Q. (By Ms. Grady) And I'm going to direct your attention to Attachment 1, page 1 of 12, and specifically I'll direct your attention to the line under Fuel & Purchased Power Expenses where it says Fuel Deferred Expense, and when I look at 2009 -- let's just skip 2009. Let's go to 2010 directly.

We've been discussing in your testimony overrecovery of actual FAC costs, and I guess my question is to the extent that there's a positive amount shown for fuel deferred expense under 2010, would that, in your opinion, would that be the overrecovery you are speaking of in your testimony?

MR. CONWAY: Your Honor, I apologize for

interjecting myself in your examination. I just would like to, again, reiterate our objection to the workpapers which are related to the October 16th filing on the same basis that we've indicated before, which is relevance.

EXAMINER BOJKO: And my ruling is the

same. Overruled.

Please answer -- I'm sorry, which page are we on?

MS. GRADY: Page 1 of 12 reflecting Columbus Southern data.

EXAMINER BOJKO: Do you need the question reread now, Mr. Roush?

THE WITNESS: Yes, please.

(Record read.)

A. I guess not exactly. What I think this is showing is really, if you're focusing back on my testimony at page 14 on lines 20 through 22 where I say: "Should projected FAC expense in a given period be less than these maximum phase-in FAC rates, the Companies may propose to increase the FAC rates to reduce any existing deferred FAC expense balance."

Well, the problem is that my testimony says that's what may happen. When you're doing modeling, you have to choose one scenario and show

it, so I think what they've chosen to show here is
that if the company did, in fact, propose to increase
the FAC rates in 2010 and '11 to reduce an existing
deferred balance, then that's what I believe this
shows, is that's what they've modeled, is that in
2010 there would actually be the opportunity to

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481

reduce the deferral further in 2011 as well.

Now, you know, that's just because when you do a model, you have to pick something to show. Is that what will be approved by the Commission in those quarterly filings to take that approach? I don't know.

Q. So, Mr. Roush, what you would interpret this Attachment 1, page 1 of 12, is showing for 2010 and 2011, that the FAC expense in those periods is less than the maximum phase-in FAC rates; is that how you would interpret it? And then the company -- let me strike that. Go ahead, answer that.

A. Yes. The way I'd interpret this is for CSP in 2010, that actual -- or, actual's kind of a funny term. Projected FAC expense for 2010 would be lower than those maximum FAC levels I set out in my testimony.

Q. Yes.

A. So, and then for modeling purposes, I think whoever did this chose to show that as writing down the deferred expense created in 2009. Now, the actual outcome I think will depend on the Commission's decision in the periodic filings as to whether they choose to do that or to leave the deferral alone and flow through lower FAC expense.

Q. Thank you, Mr. Roush.
Mr. Roush, under the company's proposal -- let me strike that.

MS. GRADY: Your Honor, if I may have a moment, I think that might be the end of my cross but I need to look at my notes.

EXAMINER BOJKO: Sure.

MS. GRADY: Can we perhaps take a five-minute break?

EXAMINER BOJKO: Let's go off the record.

(Discussion off the record.)

EXAMINER BOJKO: Let's go back on the record.

MS. GRADY: Thank you, Mr. Roush. I have no further questions.

EXAMINER BOJKO: Thank you.
Mr. Randazzo.

MR. RANDAZZO: Thank you, your Honor.

\- - -

CROSS-EXAMINATION

By Mr. Randazzo:

Q. Mr. Roush, I have a few questions for you. I will keep my voice up if you will do the same.

First of all, with regard to the

shareholders of Ohio Power and Columbus & Southern, am I correct that AEP owns all the shares in both Ohio Power and Columbus Southern?

A. That sounds correct, but I don't know that for a fact.

Q. Okay.

A. I'm not a finance guy on that.

Q. And as I took your testimony -- and I don't mean to diminish this responsibility. I've had to write a few tariffs in my life. But you have essentially taken the input from other witnesses and turned that input into rate schedules and illustrations of what the charges look like; am I correct about that?

A. Generally, yes. I'm not sure I totally agree with the illustrations of the charges for a lot of the values. It would be what the actual charge would be for some of them. Like the FAC, it may be more of an illustration.

Q. Right. But let's take the FAC, for
example. The projected fuel expense was not
something that you were responsible for developing.
You simply tried to translate that into a bill
impact, correct?

A. Yes, that's correct, into a rate and bill impact.

Q. And so if the projected fuel expense turns out to be incorrect and a new number is established, you'd have to generate new FAC charges, right?

A. Yes. That would be done in like the periodic or the quarterly filings, I guess.

Q. Or whenever. I mean, it would -- if the dollar revenue requirement for fuel is something different than what you've shown in your testimony, it would lead to a different charge in the rates, correct?

A. Yes. For example, like if the Commission issued an order saying do XYZ instead of what we've proposed.

Q. Or, hypothetically, if the Commission said that you should not be recovering capacity-related charges in the fuel adjustment mechanism, it would lead to a different specification of the charges, right?

A. Yes. I think any change the company made to the company's proposed -- the Commission made to the company's proposed FAC would change the numbers.

Q. Okay. Now, let's go to page 5. In line 5 you have in that sentence that begins on that line

"AEP Ohio is proposing." When you use the term or words "AEP Ohio," what do you mean?
A. The companies, CSP and OP.
Q. Okay. Is AEP-Ohio used in any other way in internal documents within AEP?
A. I don't know.
Q. Okay. In that sentence you begin to discuss removing the limitation on the availability of the IRP-D rate schedule for interruptible power. Why have a limit on interruptible schedules?
A. Conceptually it's kind of a balancing point to a certain extent in that your load grows over time. Your capacity needs grow over time with that load growth, and so you kind of need to balance how much additional interruptible you need with the reconciliation of, you know, factors like, well, you may not really need additional interruptible right this minute, but you need it so that you will avoid, say, needing generation in three years, four years,

five years out.

So it's kind of a balancing issue between how much you want to give because there's a rate discount associated with interruptible service. So if you kind of effectively overbuy today for a need that you might not have for a time down the road, that can -- you've got to kind of balance those.

Q. Well, I guess that brings up another question. Who's responsible for determining when the interruptible customers are interrupted? Is that done on an individual operating company basis for Columbus Southern and Ohio Power, for example, or is that done for, for example, the eastern region of AEP in general?

A. Under schedule IRP-D all Ohio customers are curtailed at the same time or asked to buy through at the same time, but that doesn't necessarily have to be concurrent with all of the AEP East companies.

Q. So from that statement would it be correct to assume that the Ohio interruptible customers are not being subjected to interruptions to -- in coordination with the use of the AEP generation fleet for the integrated system? Would that be a correct statement?

THE WITNESS: Can you read that one back,
I'm sorry?

(Record read.)

A. No, I don't think that would be a correct
statement.

Q. Well, I thought I asked you the reverse of that in the prior question and you said no. Who is responsible for determining when -- let's back up.

You do work for other operating companies other than Ohio Power and Columbus & Southern, right?

A. Yes, I do.

Q. Right. And you're aware that there are interruptible customers on the other operating companies of AEP that exist outside the state of Ohio but still in the eastern region of AEP, right?

A. Yes.

Q. Who is responsible for determining when all of those interruptible customers are asked to interrupt or curtail their usage? Within AEP who is responsible?

A. I think the responsibility lies within different areas, depending on the type of interruption or the circumstance. There could be interruptions that were the result of a transmission issue that may come from PJM or may come from the

transmission organization. There are also
interruptions that would be determined by our
commercial operations folks, and then there would
be -- I think those may be the two primary areas
where it would be either commercial operations or the
transmission folks, either directly or through PJM.

Q. Okay, either --

A. But I think where we got confused is the schedule IRP-D has some very specific terms that are Ohio-specific that may be different than the terms of interruptible tariffs or agreements in other AEP sister companies. So if there's not a -- because there is that bit of a variety, AEP-Ohio customers may be requested a discretionary interruption at a time where somebody under some different type of interruptible agreement in a different state may not be requested and maybe that's where we got disconnected.

Q. Could be.

You mentioned commercial operations. What does your commercial operations group do? Would they be responsible for managing your generation fleet?

A. I think the folks I have in mind specifically are more focused on matching up our resources in the short-term with our load in the short-term, but broadly, commercial operations manages -- one primary function is our generation operation.

Q. And they would have responsibility for trying to maximize the revenue streams that may be

available from the generation fleet; is that correct?
A. I would think that may be one of their goals, but I think their primary goal is to ensure that we have enough supply for our load. You're probably getting a little far down the path as to what all I know about commercial operations.
Q. Okay. I take it that for purposes of developing your testimony you did not consult with your commercial operations folks to determine how the interruptible service options might be integrated with their functional responsibility; is that correct?
A. I don't recall talking with them specifically about schedule IRP-D because it was an existing program that they're operating.
Q. But you're expanding the availability of it.
A. Yes.
Q. Did you talk to commercial operations

about expanding the availability of the interruptible
schedule?

A. Personally I did not. I'm sure someone
from their group reviewed my testimony.

Q. When I ask you about whether you did
something, it's a personal question.

A. Okay.
Q. Are you aware of anybody else that talked to commercial operations about expanding the availability of the interruptible schedule?
A. I don't know.
Q. Are you aware of anybody else that talked to commercial operations about expanding the availability of the interruptible schedule?
A. I don't know of anybody else.
Q. Who is responsible for communicating -- strike that.

On the bottom of page 5 you indicate that: "The interruptible service offerings allow the companies to reduce their loads when conditions on the system or conditions in the market dictate."

And I believe you discussed this earlier with nother cross-examiners, but the interruptible service offerings to the extent they're subscribed also permit the companies to satisfy their resource

adequacy obligations as established by PJM; is that
correct?

THE WITNESS: Could you read that one
back, please?

(Record read.)

A. Specifically with schedule IRP-D, that is correct, we use those -- we use the ability to interrupt those customers to meet our fixed resource requirement obligation.

Q. Right. And the fixed resource requirement obligation is the methodology that has been selected by AEP to satisfy its resource adequacy obligation to PJM, correct?

A. I believe that's correct.

Q. And if you had not selected the fixed version or the FRR version, what other approach would you have had to use to satisfy that resource adequacy obligation?

A. My understanding is the only other option is the reliability pricing model.

Q. All right. Now, why did the company select the FRR methodology? Why did the companies, the Ohio companies, select the FRR methodology?

A. I don't know.

Q. Do you know whether or not had they

selected the RPM, or reliability pricing model,
methodology for satisfying their resource adequacy
obligation there would have been any limitation on
their ability to satisfy their resource adequacy
obligation through the use of interruptible load?

A. I don't know.

Q. Have you examined the RPM model and the FRR model for purposes of offering the opinions that are reflected in your testimony?

A. I have a general understanding of the FRR and RPM model, but the basis for my testimony is the current circumstance, which is that the companies are in the FRR model for the next several years.

Q. Right. That was my next question. Once you elect the FRR version of satisfying a resource adequacy obligation, am I correct that that's a five-year commitment?

A. That sounds right. I'm not sure of the exact number.

Q. And am I also correct that it was AEP that advocated for an option like FRR at the time that the reliability pricing model was being developed within PJM?

A. I believe that's correct, but that was really not in my area of involvement.

Q. And do you know generally the difference
between FRR and RPM methodologies?

A. In a very high level, general, yes.

Q. Can you tell me what the difference is at
a very high level?

A. Under the fixed resource requirement, the companies have to demonstrate that they have adequate capacity, including to meet their load obligation, including reserve requirements. In the RPM construct the companies are effectively kind of on two sides of the equation. It's kind of like a resource clearing market so the companies would be on two sides of the equation. They would be offering their generation as in as a capacity supplier, and they would be a load-serving entity who would also be buying capacity out of that same market. So that's kind of my general understanding.

Q. So the FRR opportunity permits you to opt out of the reliability pricing model within PJM, correct?

A. I think generally that's correct, yes.

Q. And can you offer -- if you are in the FRR version of resource adequacy assurance, can you offer generation resources into the reliability pricing model market?

A. My understanding is that after you've met your FRR obligation, that if you have additional generation, that we could offer it into the RPM market up to there are some very specific limitations. I think one of them is 1,300 megawatts. Another one is some kind of percentage or something.

Q. And it's those limitations or limitations like the one you just described that AEP has been working to try and remove within PJM, correct?

A. I believe that issue is being discussed. I am not intimately involved in it.

Q. Let me ask you this, would Mr. Baker, Mr. Craig Baker, be the better person to talk to about this subject?

A. I'm sure he is more well-versed than I am on it.

Q. Should I take that as a yes?

A. Yes.

Q. Okay. Let's go to the bottom of page 6, line 20, and there on that line you use the words "unregulated entities." What do you mean by "unregulated"?

A. I think in this context I mean -- I meant unregulated from the standpoint of the Ohio Commission.

Q. Okay. So there -- you understand that the curtailment service providers that you mention on line 21 exist pursuant to a FERC, Federal Energy Regulatory Commission, approved tariff; is that correct?

A. I think that's correct, yes.

Q. And they are subject to oversight and interaction by and through PJM, correct?

A. Yes, they have to perform under the PJM tariff.

Q. And am I also correct that one or both of the Ohio companies could be a curtailment service provider but you've chosen not to be?

A. I think the companies could be curtailment service providers. I'm not sure. The definitions get a little jumbled as far as -- by their nature by being a full member in PJM allows you to be a curtailment service provider per se, kind of.

Q. If you know, do you know whether or not they're eligible to be curtailment service providers and whether or not they've elected to, if so, not take advantage of that opportunity?

A. To the second question, to my knowledge the companies have not chosen to be curtailment service providers. The first part of the question is could they be curtailment service providers?

Q. Right.

A. I think the answer to that is I think so.
I'm just struggling through the interaction between
PJM membership and Ohio law issues as far as where
that would reside so I'm not real clear.

Q. Okay. Now, on the bottom of page 6, top of page 7, you have a sentence that starts: "Even further complicating matters, if a retail customer chooses to become a PJM member, they are permitted by PJM to enroll directly in PJM programs." Why does that complicate -- further complicate things, to have a customer do directly what would otherwise be done by a curtailment service provider indirectly?

A. I think, particularly in the context of my testimony, why that even further complicates matters is that it creates a circumstance where a retail customer taking standard service offer from the company is also participating directly in the wholesale market for some -- for their demand response component.

Q. Well, I understood your testimony on that philosophical point. My question to you, sir, was why having a retail customer do directly what a curtailment service provider can do indirectly further complicates matters.

A. I think my answer, again, is that this is
a retail customer directly participating in the
wholesale market.

Q. Now, what does a retail customer have to
do to become a member of PJM?

A. I believe there's a membership fee. I'm not sure what other things are required beyond that.

Q. And is the opportunity for a retail customer to become a member of PJM something that occurs as a result of the tariff that PJM has been -- has approved by the Federal Energy Regulatory Commission, if you know?

A. My understanding is a retail customer can choose to become a member of PJM under PJM's tariff.

Q. And that tariff has been approved by the Federal Energy Regulatory Commission, right?

A. That's absolutely correct.

Q. All right. And that condition existed when AEP joined PJM, correct?

A. I believe that's correct.

Q. Yeah. And AEP elected to join PJM knowing that that requirement was in the tariff, correct?

A. I guess the word in that question I'm stumbling over is "elected."

Q. Well, at the time you were trying --
actually, at the time you were trying to participate in another regional transmission organization known as the Alliance. The Federal Energy Regulatory Commission -- do you recall that?

A. Yes.
Q. And the --
A. I vaguely recall that.
Q. The Federal Energy Regulatory Commission said no to the Alliance. Do you recall that?
A. I believe that's correct.
Q. And at that point in time gave AEP the opportunity to either pick between PJM or the Midwest ISO, right?
A. I think that's right. But I wasn't involved in those discussions so I can't --
Q. Okay.
A. I think that's right.
Q. Okay. Good enough. Now, do you understand what I mean by the word "elect"? You elected to join PJM. AEP elected to join PJM. Do you recall that?
MR. CONWAY: Objection. You've already defined election being told to take one option or

another, either MISO or PJM, and that's the context
that you've established for election, and he's given
you his answer, which is that he struggles with
whether or not that's a true election.

EXAMINER BOJKO: Mr. Conway --

MR. CONWAY: Excuse me, your Honor.

EXAMINER BOJKO: I'm sorry, so what's the objection?

MR. CONWAY: The objection is it mischaracterizes his answer.

EXAMINER BOJKO: I don't think -- I think the witness isn't answering what -- I'm sorry you don't agree with the word or word choice of the question, but the question is the question.

Mr. Roush, can you answer the question with the caveat of you don't know what the word "election" means? Mr. Randazzo's just tried to explain the painful history of this. Can you answer it based on that explanation of the word?

THE WITNESS: I will try.

EXAMINER BOJKO: Thank you.

A. The company, based on what Mr. Randazzo just said, was given the choice of joining PJM or joining MISO and chose PJM.

Q. Right. And, in fact, the obligation to participate in a regional transmission organization was a condition of the merger between AEP and Central and Southwest, wasn't it?

A. And I guess that's where I struggle, with the word "elect."

Q. Yes? Was the answer yes?

A. I believe that's correct. And that's why I struggle with the word "elect."

Q. Okay. And the condition of the merger that I just described was something that was established back in 2000, correct? If you recall.

A. That sounds about the right time.

Q. And when was AEP integrated into PJM? Would you accept approximately October the 31st of 2004?

A. I would accept that, October of 2004.

Q. Now, on page 7 you have a quote there from PJM's market monitor, is that Mr. Bowring, if you know?

A. I believe that's Mr. Bowring. And I'm not sure if it's a quote, necessarily -- it's a quote from his White Paper.

Q. I sit corrected. It's a quote from his White Paper. Did you agree with everything that was in the White Paper?

Strike the question. Did you read the
White Paper?

A. Some time ago, yes.

Q. How long ago?

A. It's probably been at least several
months ago.

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481

Q. When was the White Paper issued?
A. I'm trying to recall. I thought it was sometime last year, though it may have been early this year.
Q. And did you agree with everything that was in the White Paper?
A. I can't remember everything that was in the White Paper, but I would imagine there were probably things in that I didn't agree with.
Q. So if your imagination stands correct, then you selected this one thing that you agreed with to stick in your testimony.
MR. CONWAY: Objection.
EXAMINER BOJKO: Sustained.
Q. Do you know if Mr. Bowring or the PJM market monitor has expressed any views about the role of demand response programs in mitigating market power?
A. I suspect they have. I can't think of

anything specific right now.

Q. Okay. Let's turn to your testimony on the alternate feed service. You described a circumstance earlier during cross-examination where the primary feed or main feed of the customer is not available for service and the customer is transferred

to an alternative feed so that the customer can
continue to use electricity during that circumstance.
Do you recall that discussion?
A. Yes.
Q. You talked about a transfer switch and --
A. Yes.
Q. Yeah. In the event that the alternative
feed was not available and the primary feed was no
longer available for service, would that operate to
reduce revenues available to AEP?
A. You're asking me if the primary feed and
the alternate feed were both not available, would
that result in a revenue increase to AEP-Ohio?
Q. Revenue reduction.
A. Revenue reduction.
Q. Right. The customer's not using
electricity at that point. I don't think this is a
trick question.
A. The revenues from that particular

customer would be lower.

Q. Okay. And if the customer had an alternative feed that allowed the customer to continue to use electricity when the customer's primary feed was taken out of service, for whatever reason, then there would be continuation in the revenue stream available to AEP, right?

MR. CONWAY: Excuse me, your Honor, could I have the question reread?

EXAMINER BOJKO: You may.

(Record read.)

A. The customer would pay for the energy they use, yes.

Q. All right. Now, on lines 7 through 9 you say that: "While AEP strives to meet the needs of its customers, it is important that all customers pay charges that reflect the full cost of providing such service." Do you think that proposition has general application to the ESP case in total?

A. Not entirely, and here's why. When I think in terms of this specific line in my testimony and talking about alternate feed service, we're talking about distribution function fully regulated, traditionally regulated in Ohio, with some variance under Senate Bill 221. When I think in terms of the

standard service offer, there's -- authorized under
Senate Bill 221, there's enough of a difference that
what I would consider a universal statement in a
traditionally regulated state, like Indiana, I can't
totally get there in Ohio just because of the
uniqueness of Senate Bill 221.

Q. Okay. Well, with regard to distribution service, then, do you think that it's important that all customers pay charges that reflect the full cost of providing distribution service?

A. I think that's absolutely been a goal in pretty much every proceeding that I can recall being in. However, there's always the caveats of gradualism, et cetera, et cetera, that come into play.

Q. Right. And are the rates that AEP -- or the Ohio companies have proposed in its ESP for distribution service cost-based rates?

A. Our distribution rates were cost based when they were set back in '91 and '94, unbundled in 2000, and then the adjustment that we're proposing in the ESP for reliability and gridSMART is based on cost, so, yeah, I think I get there.

Q. That's what you mean by the use of the words "cost based" or full cost of providing such service in your testimony?

THE WITNESS: Can you read that one back?

Q. Strike the question.

A. I'm sorry.

Q. Now, on page 8 again, line 12, you say there that: "Existing AEP Ohio customers that are currently paying for alternate feed service." Can you show me pursuant to what provision in Ohio Power or Columbus & Southern's tariff those customers are currently paying for alternate feed service?

A. My recollection for CSP is it's in Exhibit DMR-9, page 11, the temporary and special service provision of the company's terms and conditions.

Q. Okay. Are you aware that both Ohio Power and Columbus & Southern have gone to existing customers with alternate feed service and asked them to execute an addendum covering the alternative feed service and suggesting to the customers that unless they sign the addendum, they're going to remove -- AEP will remove the alternative feed?

A. I think I can only answer the first part of that question, is I was aware that the company was approaching AFS customers concerning an addendum. The characterization of what that conversation would

might included, I'm not aware of what that
conversation was.

Q. You're not aware of any letters that were
sent by AEP through the customer reps to the
customers that suggested that the alternative feed
service was going to be withdrawn unless the customer

subscribed to the addendum?

MR. CONWAY: Your Honor, might I ask the court reporter, was she able to record Mr. Roush's complete answer? Mr. Randazzo followed up.

THE REPORTER: I believe so.

THE WITNESS: Can you reread the question, please?

Q. I'll rephrase it.

Are you aware that both Ohio Power and Columbus & Southern sent letters to customers with alternative feed service indicating that the customers had to execute an addendum and pay a reservation fee each month in order to retain the alternative feed service?

A. I've not personally seen such a letter, but I believe such a letter could be sent -- could have been sent to customers where the circuit was capacity deficient and in order to continue to provide AFS, the company would have had to make investments in that circuit.

Q. And that's the only circumstance that you think the letter might have been sent?

A. That's the only one I can think of.

Q. And how much revenue is AEP currently generating from the customers who are currently

paying for alternative feed service on an annual basis for Columbus Southern and Ohio Power?
A. I don't know that.
Q. How much revenue are you projecting to collect on an annualized basis?
A. The current level, but I don't have that number.
Q. Are all customers with alternative feed service currently paying for alternative feed service?
A. No. And I don't believe they would under the company's proposal in 2009 either.
Q. But you don't know how much revenue in total would be generated as a result of making this tariff modification to establish schedule AFS?
A. The only -- there would be no additional revenue of any certainty by establishing schedule AFS. It's indoctrinating basically the company's current policies that are handled by a special

contract addendum, so at a time a circuit becomes capacity deficient, the customer makes a decision whether they want to continue the AFS or not and so there is no certainty of additional revenue.

Q. Mr. Roush, you've got customers that are currently paying for this now, right?

A. Yes.

Q. Okay. And you don't know how much revenue is associated with that?

A. I don't have it with me.

Q. Would it be appropriate in the interest of customers paying no more than the full cost of their service to reduce distribution rates by the amount of revenue that you collect for alternative feed service?

A. In the context of a full distribution rate case, revenues collected through alternate feed service would be an offset to the remaining distribution rates.

Q. Would be an offset to the distribution revenue requirement, correct?

A. Well, they would be part of the distribution revenue requirement and would reduce the rates collected through the non-AFS distribution rates.

Q. Okay. I'd like to ask you a couple of questions about the Hospital Exhibit No. 2 Mr. O'Brien talked to you about earlier in the day. Do you have that handy?

A. Yes, I do.

Q. It's a two-page document.

MR. CONWAY: It's a three-page document.

MR. RANDAZZO: Or three pages, excuse me, yes.

MR. CONWAY: One is two sided.

Q. Now, if you would go to page 2 of 2 there --

A. Okay.

Q. -- you show the coincident demand for voltage levels; is that correct? In column 2.

A. Yes.

Q. And is the coincident demand value shown there the billing determinants that you used to develop the unit charges?

MR. BELL: Objection.

EXAMINER BOJKO: Grounds?

MR. BELL: Asked and answered. That was the very question Mr. O'Brien asked and the witness said yes.

MR. RANDAZZO: Okay, I'll strike the

question. I'll take Mr. Bell's word for it. Trying to move things along here.

MR. BELL: I'm trying to help out Mr. Resnik.

Q. In the spirit of cooperation then, are you an engineer?

A. No, I am not.

Q. The words "coincident demand," based upon your prior discussion, are used to describe the demand coincident with the overall system peak; is that correct?

A. With the overall -- the overall system peak in terms of, for example, the primary system, the overall peak on the primary distribution system, although this may be -- I'm trying to recall now if this is a 1 CP or a 12 CP.

Q. Well, I think that was my question. It says coincident demand, singular, okay?

A. Okay.

Q. You tell me what that reflects.

A. I'm just having trouble recalling from these 15-plus-year-old cases whether these were 12 CP demands or 6 CP demands or 1 CP demands. I just don't recall --

Q. Well, if you know, for design purposes,

as you move from generation function to transmission
function to distribution function, isn't the design
at the distribution level more related to
noncoincident demands than coincident demands? If
you know.

A. I think specifically in the context of the AFS, since we're looking at the cost of the facilities that are there to stand ready and be available at all times subject to normal utility outages, that the appropriate measure for designing this was the coincident demand.

Q. So the AFS charge, as you characterize it, is more of a standby charge?

A. I think it has some similarities to standby charges, and this is very consistent with the way those are designed as well.

Q. Well, are there any generation-related costs in your proposed AFS rate?

A. No.

Q. Any transmission-related costs?

A. No.

Q. And what is it that you are standing by to do through an alternative feed service?

A. You have redundant transformer and redundant circuit capacity built, planned, built, and set aside for when a customer's main circuit fails for them to be able to transfer their load to this alternate circuit and station transformer and continue operating.

Q. Okay. And those would be distribution system-related costs?

A. Yes.

Q. Is the distribution system sized based upon demands at the coincident peak or based on noncoincident peak, if you know?

A. I think we've gotten tangled up in language a little bit, Mr. Randazzo. The coincident peak that we're showing here -- and forgive me, I don't recall whether it's 1, 6, or 12 -- is meant to be coincident with the peak on the primary distribution system, so it would equivalently also be a noncoincident peak for the primary distribution system. It's not at the time of the generation system peak. It's at the time of the peak on the primary distribution system.

Q. And how did you gather that information?

A. Through load research, development of load research and -- which would have developed hourly loads for all the rate classes, build that up by secondary, primary, and then all the way up.

Q. So you took -- you were able through load research to develop the coincident demand at the primary voltage level?

A. Yes.

Q. Is that what you're saying?

A. Yes. And then this would only be the

values for Ohio Power, for example, for the GS-2, GS-3, GS-4 classes, so it's secondary and primary voltage customers served on GS-2 and GS-3, their demands at the time of the peak on the primary distribution system. And whether it's 1, 6, or 12 coincident peaks, my memory fails.

Q. And what is the total demand of all customers on the primary system at the time of the -- that you --

A. I'm sorry, you -- no -- I don't recall. I don't recall. I don't have that.

Q. Let's move on. On line 20, page 11 you make reference to the transmission cost recovery rider, and there's already been some cross-examination on whether or not the transmission cost recovery rider, otherwise referred to as the TCRR, will be included for purposes of determining whether or not an increase goes above the 15 percent cap. Do you recall that?

A. Yes, I do.

Q. Am I correct that the Ohio companies have proposed to increase the TCRR?

A. My recollection is that one of the companies is seeing an increase; the other company is seeing a decrease in total.

Q. Which one, do you know, is seeing the increase?

A. I believe Ohio Power is the one that's seeing the increase.

Q. All right. And between Columbus & Southern and Ohio Power, the Ohio Power customers are seeing the greatest increase otherwise; is that correct?

A. I'm sorry, in what context?

Q. The Ohio Power customers in general are seeing the greatest increase as a result of the proposed ESP; is that correct?

A. I guess I'm not sure how to make that comparison. If I just look --

Q. You don't know whether the Ohio Power customers or Columbus & Southern customers --

MR. CONWAY: Objection.

Q. -- which one of those is seeing the greatest increase under the proposed ESP?

MR. CONWAY: Objection. He wasn't finished answering.

MR. RANDAZZO: I'm sorry.

A. If I look at my Exhibit DMR-1 for 2009, I'm showing CSP customers seeing a 13.41 percent increase and OP customers seeing a 13 percent increase. However, as was discussed earlier regarding I think OCC Exhibit 6, it appeared that there was the possibility or potential that CSP may not have deferred fuel by the end of 2011 whereas I think OP may. So just because of those different comparisons I'm not there with you.

Q. Okay. I'm making this harder than it needs to be, I think. On page 14, line 12 carrying on to line 13, you indicate there that the phase-in of the FAC was accomplished while still having total bill increases of approximately 15 percent. Do you see that?

A. Yes.

Q. Good. For purposes of applying the 15 percent limitation, you have not factored into the analysis any increases in transmission-related charges, right?

A. Or any decreases, no, that's correct, I have not factored the TCRR into the approximate

15 percent determination.

Q. Okay. Now, at the bottom of page 14 you begin to discuss the -- or continue to discuss the mechanical structure of the FAC mechanism with there indicating the amounts deferred in the FAC mechanism and remaining at the end of 2011 will be amortized and collected through a nonbypassable rider in the years 2012 through 2018. All right?

A. Yes.

Q. So the nonbypassable rider that you're proposing in this ESP proceeding will actually have a life beyond the term of the ESP itself, correct?

A. It will continue after the SSO rates established in the ESP expire.

Q. Will it continue in the event -- based on your proposal here, will it continue in the event that subsequent to the three-year term of the ESP the Ohio companies of AEP elect to pursue a market rate option?

A. My understanding is yes.

Q. And then the next sentence on the top of 15, the first sentence that begins on the top of 15 says that beginning in 2012 you're going to eliminate the maximum phase-in -- and I'm paraphrasing here -- and that the FAC will operate in a traditional manner with periodic adjustments. Do you see that?

A.   Yes.

Q.   So as I understand this aspect of the proposal, you're proposing to establish a fuel adjustment mechanism that will also have a life beyond the term of the ESP; is that correct?

A. We're proposing to establish an ongoing FAC mechanism.

Q. Beyond the term of the proposed ESP, correct?

A. Yes. It will continue to operate beyond the end of 2011.

Q. All right. And that would be true, again, as in my prior discussion with you, that would be true even in the event that we come to the end of the ESP that's approved by the Commission in this case, if there is one, and you elect a market rate option?

A. Yes, I believe that's correct.

Q. And how will that work with the market rate option?

A. I guess in general it would work the way Senate Bill 221 has it laid out, that there would be -- that the FAC would include the items as the company has proposed here.

Q. Are you aware that the market rate option
involves a competitive bidding process?

A. Yes.

Q. Would you propose that fuel not be
included in the competitive solicitation in the event
that the company elects the market rate option?

A. I guess I view the market rate option as a blend, a blend of the competitive bid source and this source, so -- and the noncompetitive bid source. So the amounts in the FAC would be the noncompetitively bid fuel and then blended in with the competitively bid purchased power kind of is the way I view it.

Q. Don't you have slice of system in your FAC as proposed? Don't have you purchased power in your FAC as proposed?

A. During the ESP period?

Q. Yes.

A. During the ESP period we are proposing to purchase power.

Q. And recover it through the FAC in that case, right?

A. Yes.

Q. But the FAC as you're proposing in this proceeding would be -- would have an ongoing

perpetual role for purposes of charging your
customers in Ohio. Is that the way we should view
this?
MR. CONWAY: Objection. He didn't say it
was perpetual.
EXAMINER BOJKO: Can you rephrase,

Mr. Randazzo?

Q. How long, if approved, would the FAC mechanism last?

A. Until the Commission modified it.

Q. All righty. On page 15 you indicate that if your ESP is approved, that you would be filing tariffs in effect for one year, and then in the fourth quarter of 2009 and 2010 you would file compliance tariffs for the years 2010 and 2011 respectively.

What billing determinants would you use for purposes of developing the tariffs?

A. The rates would all be set in the Commission -- in the original order as I've calculated them in Exhibit DMR-2 and DMR-3, so the rates would all be approved. All it would be doing would be updating the numbers on the page based on previously approved values.

So these were all -- all of the rates

were designed applying -- you know, most of them
applying current rates, taking current rates and
applying 3 percent or whatever percentage increases
to them, so Exhibit DMR used forecast 2009 billing
determinants.

But another way we envision, if the

Commission approves our ESP, the rates as shown in DMR-2, DMR-3 for all years of the ESP would be the rates that would be approved, and then all we would be doing is filing to update to those numbers each year so we didn't have multiple tariff sheets on file.

Q. Okay.

MR. RANDAZZO: That's all I have, Mr. Roush. Thank you.

THE WITNESS: Thank you.

EXAMINER BOJKO: Let's take a 20-minute recess. Be back here at 5 after 4.

(Recess taken.)

THE EXAMINER: Let's go back on the record.

Mr. Roush, you're still under oath.

THE WITNESS: Yes, your Honor.

EXAMINER BOJKO: Ms. Wung, would you like to continue?

MS. WUNG: Yes, your Honor, just a few
questions.

EXAMINER BOJKO: Or begin.

- - -

CROSS-EXAMINATION

By Ms. Wung:

Q. Good evening, Mr. Roush. My name is Grace Wung, here on behalf of The Commercial Group. I just have a few follow-up questions.

With respect to page 6, lines 1 through 4 of your direct testimony, if we could just turn to that.

A. Yes.

Q. There you say: "In other words, the Companies should be able to count the load that is capable of being reduced towards peak reduction goals, even if that load is not reduced at the time of the peak because operational and/or market conditions did not dictate the need for a reduction." Is that correct?

A. Yes.

Q. Do you remember the previous line of questioning with respect to these four lines?

A. I believe so.

Q. Okay. Would it be fair to say there that -- is it one of the reasons you believe AEP should be allowed to credit the capability, that essentially those demand response reductions are available for reduction?

A. Are you asking me if because we have the ability to ask for those demands to be reduced, if that's the reason why I'm suggesting that we should be able to count that towards --

Q. Yes. Would that be one reason?

A. Yes.

Q. Thank you.

Going back to questions that you had from OCC's counsel and also from Integrys's counsel there was a discussion about the changes to the IRP discretionary tariff.

A. Yes.

Q. Do you recall that line of questioning?

A. Yes, I do.

Q. And in there you indicated that there were several reasons that you believed that currently there are not many participants on the IRP discretionary program; is that correct?

A. My recollection of most of the discussion was around the ECS and PCS and why there was meager interest in those. But there are, I believe, seven customers on IRP-D between the two companies, I think.

Q. Okay. For all those types of programs, then, with respect to what AEP has available for demand response programs, your recollection was that

there either are little or seven customers on those
types of programs.
A. That's correct. And I don't want to
mislead you. The seven customers add up to quite a
few megawatts on the IRP-D.
Q. But that was also one -- these factors
were one of the considerations that you'd reduce the
3 megawatt load to the 1 megawatt requirement.
A. That's correct.
Q. Was to encourage additional parties or
make more parties eligible to participate in these
programs.
A. Yes, you're correct.
Q. Did you guys make -- did you make an
inquiry with existing customers as to why there
wasn't more participation?
A. Not directly. I'd gotten some feedback
from customer service folks through discussions over
quite a period of time, but I didn't speak directly

to customers.

Q. And when you decided to go to the 1 megawatt level, did you also speak with customers with respect to that level?

A. No, I did not.

Q. So have you inquired of any customers the reasons why they may or may not be participating in your demand response programs?

A. No, I have not spoken directly to any customers about that.

Q. With respect to the demand response programs that you are now proposing and the changes you are proposing in your IRP discretionary tariff, is the goal to encourage further demand response participation?

A. Yes. I think one of the company's goals is to encourage additional demand response participation.

MS. WUNG: Thank you, Mr. Roush. That's all the questions I have.

EXAMINER BOJKO: Mr. Rinebolt.

MR. RINEBOLT: Thank you, your Honor.

\- - -

CROSS-EXAMINATION

By Mr. Rinebolt:

Q. Good afternoon, Mr. Roush.

A. Good afternoon, Mr. Rinebolt.

Q. All my questions pertain to Exhibit DMR-5, which is your calculation of the provider of last resort.

A. Yes, sir.

Q. I notice on the chart for Columbus Southern Power Company that residential customers would be responsible for roughly 46.8 million of the 108.2 million in revenue collected. Is that an accurate reflection of your chart?

A. Yes, I believe it is.

Q. To your knowledge, have any residential customers ever shopped in the Columbus Southern Power service territory?

A. My recollection is that there were residential customers that shopped quite a few years ago back in like the 2001-2002 time frame.

Q. Back when people were excited about choice, right? Strike that.

Are there any residential customers shopping currently?

A. Not to my knowledge.

Q. All right. Then if the POLR charge is to protect the company from the risk of customers leaving and returning to the system and currently no residential customers shop, why are you allocating somewhere around 43 percent of the cost of the POLR obligation to residential customers?

A. Let me break that into two parts. The first part I think is probably better to chat with

the now departed Mr. Baker regarding the
determination --
Q. I intend to.
A. And I mean departed from the room, not
from . . .
Q. Yeah. Well, it wouldn't be any fun if he
was truly departed.
A. The second part of the question, the
allocation to the classes is consistent with how it
was previously allocated in the company's RSP cases
in accordance with the Commission order, which was a
demand-based allocation to the classes.
Q. So that demand-based allocation, what
allocation methodology does that reflect? Is that a
conventional rate design methodology?
A. I would say it's a somewhat conventional
allocation of responsibility based upon contribution
to the peak demands.
Q. All right. But if no customers are

shopping, where is the cost causation associated with the POLR charge? If no residential customers shop, how are they causing a POLR cost?

A. I think this starts to get a little far afield for me, but in general -- let me correct one thing. You're absolutely correct, no residential customers are shopping. Columbus Southern Power does have shopping customers.

I think the allocation basis is tied primarily to the load, the overall megawatts of load, and then also the determination of the risk that's much better addressed by Mr. Baker.

So I think the linkage is really the quantification of the POLR is tied to all the things that Mr. Baker talks about, and once you've quantified that, you look at the amount and then look at the exposure within the -- the megawatts of exposure within each class, is kind of the basis that I see.

Q. And appreciating that this may be a more appropriate question for Mr. Baker, but given that you are a rate design specialist, did the company -- if no one is shopping right now -- and I'd ask you to accept, subject to check, that there are no marketers making offers to residential customers right now in

Columbus Southern.

A. I'll accept that, subject to check.

Q. Yeah. Then where is the risk that a residential customer would leave? How do you calculate that? I'm trying to figure out what the risk is since there's no place to go.

MR. CONWAY: Objection. I think he's answered that he can take Mr. Rinebolt so far but that the witness that's being presented to describe the nature of the risk, the cost of the risk, and how the dollars that are proposed for recovery through the POLR charge are calculated is Mr. Baker.

MR. RINEBOLT: Your Honor, in response, I'm merely following up on the witness's last answer when he said, you know, you're looking at factors that are associated with total demand, peak demand, and the risk of shopping. I'm just --

EXAMINER BOJKO: The witness can --

MR. RINEBOLT: -- asking his opinion.

EXAMINER BOJKO: -- answer if he knows, if he doesn't know, then --

THE WITNESS: I'm sorry, I've lost the question. Would you mind reading it back?

Q. It was a little garbled. Let me rephrase. All right?

A. Thank you.

Q. Accepting that there are no customers shopping and that there are no marketers making offers to residential customers, can you tell me what you think the risk is of residential customers shopping?

A. I guess, in my opinion, the view is more prospective looking, that you're looking at the risk over the ESP period, but that's -- rather than a point in time today.

Q. Well, the people who, in a sense, cause you to need a POLR charge are those that indeed do shop, so did you consider charging a POLR -- having the POLR charge be levied only on customers who shop?

MR. CONWAY: Objection. That mischaracterizes his testimony. He didn't say that the only people who should be paying a POLR charge are the ones who have shopped.

MR. RINEBOLT: Your Honor, I just asked if they considered using that as an allocation factor in the --

EXAMINER BOJKO: He did say "did you consider."

Mr. Roush, did you consider it?

THE WITNESS: Did I consider?

Q. Allocating responsibility for POLR charges only to customers who shop.

A. No, I did not consider that.

Q. Just a couple more questions that relate to the Ohio Power chart. In the Ohio Power chart the rates for GS-1 and GS-2 customers are actually higher than the rates for residential customers, at least under the current structure and under your proposed structure. Can you tell me why the rates for GS-1 and GS-2 are higher on a percentage basis than the residential customer rate?

A. I think you mean on a per kilowatt-hour basis?

Q. Yeah, on a per kilowatt-hour basis.

A. Certainly, since the current POLR responsibility was allocated to the classes based upon demand, and then once you did that allocation you then unitized it based on kilowatt-hours, what that tends to tell me is that the Ohio Power GS-1 and GS-2 customers had fewer kilowatt-hours per kW of peak demand than did the residential customers.

Q. One last question. If you know, regarding both companies, which customer class has done the most shopping?

A. In general I believe it's the commercial customers of Columbus Southern Power Company, so they might be on GS-1, GS-2, or GS-3, generally.

MR. RINEBOLT: Thank you very much, Mr. Roush. Appreciate it.

THE WITNESS: You're welcome.

EXAMINER BOJKO: Mr. Boehm.

MR. BOEHM: Yes, thank you.

- - -

CROSS-EXAMINATION

By Mr. Boehm:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. Some of these questions may indeed turn out to be questions for Mr. Baker, but I think you can probably answer some.

Can we go to your Exhibit DMR-1? Let's just, for example, let's just do page 1 of 2 and look at the POLR provision under current rates, which I think is 14,580,921.

A. Yes, sir.

Q. Now, this or something like this was collected or being collected from ratepayers under the existing RSP of the company; is that right?

A. Yes, that's correct, there's a current POLR charge.

Q. And we know, I suppose, from the testimony of Mr. Baker that the future POLR charges are being calculated based on an option -- an option concept using the Black-Scholes method, right?

A. That's my basic understanding, yes.

Q. Do you know how this 14 million

580 dollars -- $14 million was calculated?

A. Just to be clear, the 14,580,921 here or the rates that underlie that?

Q. Either or both. Let's start with the gross number. Do you know how that number was calculated?

A. Yes, I do.

Q. Was it calculated using the Black-Scholes option model?

A. It was calculated applying the approved POLR rates for Columbus Southern Power to forecasted 2009 usage.

Q. Okay. Do you know how the approved POLR rates were calculated?

A. My recollection from the RSP case was that the company sought collection of certain cost items. The Commission did not approve the basis -- or, a particular basis for the cost items but said that level of collection was -- that level of -- that amount of dollars represented was a reasonable level for POLR collection back during the RSP. That's my general recollection.

Q. Okay. And do you understand, Mr. Roush, that this $14.5 million is being -- or do I understand correctly that it's being added to the

$93 million to come up with the Columbus & Southern
recommended POLR charge of $108 million?
A. I think your understanding is correct. I
calculated the 14.5 million saying this is what
current rates would collect. Mr. Baker gave me the
108 million that said this is what should be
collected. So the difference is the 93.6 million.
Q. Okay. But essentially we don't know how
the 14.5 was calculated except that that was the
result of the Commission order.
A. In the RSP the company sought cost
recovery around that, you know, that added up to
rates that would produce this $14.6 million today for
some specific items. I just am drawing a blank on
what those items were right now.
But ultimately the Commission in its
order determined that those dollars -- that was an
appropriate dollar level to establish a POLR for the
companies. So I think generally you're correct, it

was the result -- the outcome of the Commission's
order in the RSP proceeding.

Q. But that order doesn't by its terms go
past the RSP period, does it? It doesn't go past
2008.

A. I guess I'm avoiding trying to get into the same swamp I got into with Mr. Randazzo by its terms issue. The RSP did authorize certain things to be deferred to be collected post 2008 so there are some aspects of it that --

Q. Of the POLR money?

A. Not the POLR. I'm just thinking the RSP in total, not trying to nitpick with you.

Q. And I'm not going to do it with you either, okay? I'm just talking about the POLR now, okay?

A. Sure.

Q. The POLR by its terms doesn't go past 2008 as far as your understanding, right?

A. My understanding is none of the RSP rates go beyond the end of 2008, at least as originally contemplated. Now Senate Bill 221's changed some of that.

Q. Okay. So with respect -- and everything we just said about Ohio Power is true of the POLR amount of 39.7 million -- I'm sorry. Everything we just said with respect to Columbus Southern is also true with respect to the $39.7 million POLR charge on DMR-1, page 2 of 2, for Ohio Power Company; is that correct?

MR. CONWAY: Objection. It's vague,

ambiguous, everything that we've said about the one is --

MR. BOEHM: Well, we'll do it the long way. Again, if you want to stay --

Q. Let me ask you something, Mr. Roush. Do you know whether the $39.7 million was calculated pursuant to the Black-Scholes method?

A. No, it was not.

Q. Okay. Do you know whether that was the result of a Commission order which compromised the company's initial proposal for POLR?

A. It was the result of the Commission's -- it came about as a result of the Commission's modifications to the company's RSP filing, so . . .

Q. Okay. And do you know in the company's calculation of the Black-Scholes method how this, for instance -- now that we're on 2 of 2 for Ohio Power Company, was this $39.7 million which is added to the $21 million, as I understand it under the company's

proposal, was that $39.7 million justified by virtue
of some Black-Scholes analysis?
A. In the context of the RSP, no, it was
not. In the context of the ESP, Mr. Baker supported
the aggregate number of roughly 60 million for, looks
like, roughly 61 million for Ohio Power, if you want

to disaggregate it between the two.
Q. Based on the Black-Scholes.
A. That's my general understanding, yes.
Q. It sounds like a question for Mr. Baker then.
Can you tell me, of this $39.7 that was collected by the company, was there a corresponding expenditure for that amount of money by the company?
A. No, I cannot tell you of any specific item.
Q. The company didn't pay $39.7 million for an option or anything, did they?
A. Not to my knowledge. Just to be clear, the 39-7 is a projection of what current rates would collect in 2009.
Q. Current rates would collect in 2009.
A. Just to be clear, whatever we --
Q. Okay.
A. -- are collecting under those rates might

not be 39-7, if you're looking backwards.

Q. Ballpark, around 39-7, right?

A. I just didn't want to mislead you.

Q. I understand. But as far as you know, there has not been a corresponding expenditure of money by the company of $39 million to somehow

protect or to provide the POLR protection.
A. I'm not aware that we bought an option or anything like that. I'm also not sure whether there would have been other underlying costs that the company might have incurred. I just -- I don't know.
Q. And if that weren't so, then that $39 million would go right to the company's bottom line; isn't that right?
A. I believe your math's correct. You're saying if there were revenues with no expenses --
Q. Wouldn't that go to the bottom line?
A. Yeah; after you pay the taxman, of course.
Q. The answer is yes, though.
A. Yes.
Q. Thank you.
And with respect to the forecasted amounts of money that will be collected under a POLR, do you know whether it's the company's intention to

buy some sort of option?

A. I don't know. That's a Mr. Baker one, I'm sure.

Q. Okay. And if, in fact, the company didn't buy an option -- well, let me back up a little bit.

Is this amount of money -- well, strike that as well.

In calculating the amount of this POLR charge, now, Mr. Baker had listed in his testimony I believe a number of inputs on page 31 or 32 of his testimony that were involved in the input of the calculation; did he not? I think he's got them listed on page 32. Do you have -- I'm sorry, Mr. Roush, do you have his testimony up there?

A. I was just looking to see if I did.

Q. Okay.

A. I see that in his testimony.

Q. And one of the inputs is the market price; isn't that correct?

A. That's what it says on page 32.

Q. Okay. And if, in fact -- and the function that the market price or the effect of the market price on the analysis is essentially that the higher the market price -- the higher the market price, then logically the higher -- the greater the amount of POLR that the company would want to protect itself; is than correct?

MR. CONWAY: Objection.

EXAMINER BOJKO: Grounds?

MR. CONWAY: It's well afield of

Mr. Roush's testimony. This is -- he's cross-examining him now about Mr. Baker's testimony.

MR. BOEHM: Your Honor, that may be so, but he's got his numbers down here, and I understood that he was responsible for calculating those numbers.

MR. CONWAY: Your Honor, he took the value that Mr. Baker calculated for the cost of the POLR -- of taking on the POLR obligations and he crafted rates to recover them, and he's explained that he did not get into risk calculating or the costing of the risk that Mr. Baker is responsible for.

EXAMINER BOJKO: I'm not clear of the line either. So if the witness knows, he may answer. If the witness doesn't know, then he is free to punt to Mr. Baker as he's done in the past.

THE WITNESS: Can you please reread the question?

(Record read.)

A. I'm not sure that sounds right to me, but I'm really not the expert. You need to talk to Mr. Baker.

Q. Okay. We'll talk to him.

Do you know, Mr. Roush, what the date was or dates were with respect to the prices the company used in developing the market price?

A. No idea.

Q. Would Mr. Baker know that?

A. I think so.

Q. Okay. Now, as I understand this, Mr. Roush, the POLR charge is to protect the company against parties who have gone shopping coming back to the company and whether pursuant to Commission rule or the Commission changing some rule getting the company to supply them with power at tariff rates; is that right?

MR. CONWAY: Objection.

EXAMINER BOJKO: Grounds?

MR. CONWAY: That's a flat mischaracterization of Mr. Baker's testimony.

MR. BOEHM: It is not a mischaracterization. It's a question, and I would like him to answer it. Counsel's been answering all the questions. I'd like the witness to answer one.

EXAMINER BOJKO: Okay. Let's focus any kind of objections or responses to the Bench.

MR. BOEHM: I'm sorry. Excuse me, your Honor. It's a question.

EXAMINER BOJKO: I agree, I think the

witness needs to be able to answer the question. If the witness cannot answer the question, then the witness needs to say so.

Mr. Roush, answer the question or say you cannot answer the question.

MR. BOEHM: Would you like the question read back, Mr. Roush?

THE WITNESS: Please.

(Record read.)

MR. BOEHM: And your Honor will point out there was no mention whatsoever of Mr. Baker in the question.

EXAMINER BOJKO: I heard the question the first time, Mr. Boehm.

MR. BOEHM: Thank you.

EXAMINER BOJKO: I am up here for a reason.

MR. BOEHM: Excuse me, your Honor, I meant no disrespect.

A. Unfortunately there will be a reference to Mr. Baker in the answer. Mr. Baker is clearly the witness responsible for supporting the POLR revenue request. What I have done in my testimony is take the total amount of POLR as he has supported and justified it and allocated it to the rate classes.

EXAMINER BOJKO: Thank you.

Q. Thank you, Mr. Roush.

Can I refer you to page 12 of your testimony, Mr. Roush? You talk on page 12 about "The Economic Development Cost Recovery Rider will be the mechanism by which the Companies recover the cost, incentives, and revenues foregone associated with the Commission-approved special arrangements." Are you aware of any of those special arrangements being negotiated right now by any of the AEP companies?

A. I'm aware of one agreement that's been approved with Globe Metallurgical, one agreement that is, I believe, still in process with the Commission with Solsil, Inc., and if there are other conversations going on, I'm not involved in those directly.

Q. Are you aware of whether there's any conversations going on between the company and Ormet?

MR. CONWAY: Objection.

EXAMINER BOJKO: Do you have a grounds, Mr. Conway?

MR. CONWAY: It's not relevant, your Honor, whether the company is or might be having discussions with them.

MR. BOEHM: Your Honor, I think it's very relevant.

EXAMINER BOJKO: I think the witness has told you the ones he's been aware of, so I think the question's been asked and answered.

Q. Okay. We'll move on, then. Are you aware that -- let's put it this way: Has Mr. Baker in his testimony provided any insight as to whether or not the 7 percent and the 11 percent increase that you calculate represents some sort of recovery for the Ormet or Mon Power contracts' delta?

A. I'm sorry, I'm confused. I'm not sure which 7 percent and 11 percent.

Q. I'm sorry, Mr. Roush, I'm getting used to referring to the 7 percent -- I'm sorry. Strike that.

Are you aware of whether or not Mr. Baker, with respect to the 5, 10, and 15 percent power purchases that he recommends has attributed the need for those power purchases to cover the Ormet or Mon Power power needs?

A. I believe he discusses those in the context of the 5, 10, 15 percent, but I think you're better to ask him about that than me.

Q. Well, okay. Let me see if I have any

more . . .
It is true -- just following up on one thing, Mr. Roush. In the last, say, three years if any of the utility companies lost a customer who was paying for their power at tariff rates, wouldn't that represent an opportunity for the company to make more money by selling that power into a higher market?
A. You're asking me if the company in the past few years lost a customer, would they make more money by losing the customer than having the customer.
Q. Because it would present an opportunity for them to sell that power not at tariff rates but at market prices, which are higher.
A. I guess I'm struggling with that on a holistic basis because there would also be lost distribution revenues and other items, so I'm not sure I can definitively reach that conclusion with

you.

Q. Okay. Let's take a large industrial customer. Let's take Timken, God forbid. Timken shuts down last year. Timken shuts down. Would that represent a loss to the company, do you believe, or a revenue opportunity?

A. I'm not sure I can make that calculation on the stand here because there are too many different issues that you have to figure out, you know, to the extent that there would be hours when the market was higher than what they were paying in those times, but there would be other times when maybe they free up power but there's no market for it. So I think there's just too many variables to make that calculation on the stand here.

Q. Well, maybe we'll talk to Mr. Baker about that then, too.

One more thing. What if a company said to -- a customer said to Ohio Power not just, "Well, when I go back to you, if I leave you and I come back, I'll pay market prices," but what if they said to you at the very beginning, "I won't leave you. I pledge to you, I waive my right to go shopping. You're mine for the next three years," what would the POLR risk be for such a customer?

A. That's a good question. I'm not sure.
The only frame of reference I have to view that is kind of the flip, which is what Senate Bill 221 established, which was that for folks within a governmental aggregation that said I'm giving up my -- I'm forever giving up my right to return to

standard service offer, that those customers would be able to, I believe, avoid POLR, I'm just not sure the mirror image matches up.

Q. Can you think of any reason why it doesn't?

A. I can think of it in terms that, you know, a three-year commitment not to leave doesn't necessarily sync up with the planning horizons for generation capacity and those types of issues. But that's about as far out as I can get with that. That's probably better, again, to talk to Mr. Baker about POLR.

Q. Okay. Well, let me just -- one question. Under the old paradigm where customers couldn't leave, under the old regulated paradigm where you were the monopoly provider for power in certain service territories, you didn't ask for a POLR provision then, did you?

A. I guess in my mind in the old traditional regulatory world that POLR obligation was kind of by definition within rates.

Q. Okay.

MR. BOEHM: No further questions, your Honor. Thank you.

Thank you, Mr. Roush.

EXAMINER BOJKO: Mr. Bell.

MR. BELL: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Bell:

Q. Mr. Roush, I'm going to attempt to abbreviate our dialogue this afternoon by starting out in the same step that Ms. Grady and Mr. Randazzo attempted to walk earlier in their cross-examination.

Directing your attention to page 2 and 3, you state the very purpose of your testimony, do you not, as being to discuss certain features, one, to summarize the company's requested rate relief as supported by a number of company witnesses, and to explain the design of the company's proposed rates and riders and for the resulting rate impacts; is that correct?

A. I think that's a pretty good synopsis of my testimony on page 2 and 3.

Q. Stated differently, as reflected in the cross-examination of my departed friend Mr. Boehm, you are not tendering yourself as being a witness of the company to support the merits of any of the company's specific proposals, are you? For instance, the POLR charge amount, Mr. Baker determined that.

And other witnesses determined -- were tendered to support the merits to the extent that they exist of the company's proposed increases, correct? Isn't that what your testimony on page 2 and the top of page 3 says?

A. I think in general other company witnesses discuss the merit of particular proposals, but in some items I would be the one that would have -- some items I may have been actually the one that calculated the revenue requirement for those things, for example, reliability and gridSMART based on the costs provided me by those folks, et cetera.

Q. Those are a very, very, small, minuscule component of the overall revenue requested in the ESP, are they not, Mr. Roush?

MR. CONWAY: Objection.

EXAMINER BOJKO: Grounds?

MR. CONWAY: He's talking over the witness before the witness is done giving his answer.

MR. BELL: I'm sorry, his mic may have gone out and he fell off again. I thought he completed his answer.

Q. Is your mic working, Mr. Roush? Okay.

EXAMINER BOJKO: Okay, gentlemen. It's 5 o'clock. Let's try to get through this as painlessly as possible.

Mr. Roush, if you can answer his questions, please do. If you need help, let us know.

THE WITNESS: Thank you.

Can you read that one back, please?

(Record read.)

A. The distribution reliability and gridSMART are about 7 percent of the overall request in this proceeding.

Q. In what, the first year?

A. Looks like roughly across all three years, just as a rough ballpark.

Q. Okay. I'll pursue that in a moment. Be that as it may, picking up on the examination of my good friend Mr. O'Brien and Mr. Randazzo with respect to the alternative feeds and the interruptible service riders, with respect to the alternate feed, is it your position, Mr. Roush, that the capacity deficiency existing on a circuit causing the customer

to desire an alternative feed to another circuit,
that that deficiency was caused by the customer
requesting the alternative feed?

A. I don't understand your question.

Q. Okay. With respect to the circuits on
which customers have alternative feeds, are you

familiar with those circuits, the nature of those circuits today?

A. I guess what do you mean by the nature of the circuits?

Q. Well, the voltage level of the circuits.

A. For a --

Q. For those customers desirous of having an alternative feed, are they distribution voltage levels?

A. For a standard alternate feed service customer?

Q. Yes.

A. The general paradigm is they are taking service at the primary delivery voltage and desire a redundant primary distribution transformer and distribution circuits.

Q. And do you know in general on average how many customers are served on such a circuit?

A. I would have no idea what it would be on average.

Q. Okay. You're not an engineer, I believe you indicated in response to prior questions; is that correct?

A. That is correct, I'm not an engineer.

Q. Do you have any experience whatsoever in the operation or maintenance of a distribution system?

A. I have never worked in distribution operation or maintenance.

Q. How about distribution system planning?

A. I have not worked in distribution system planning.

Q. Do you know what factors are considered by system designers for planning capacity for a distribution circuit?

A. I have some general knowledge, but clearly Mr. Boyd was the expert on that --

Q. Well, for instance, I'm making reference again to an exhibit that the Ohio Hospital Association inquired of you on, and Mr. Randazzo, and you initially, if I interpreted your testimony -- and I'm not trying to color it. I thought that you said initially that those circuits were based upon system coincident demand in response to Mr. Randazzo's

examination, three or four questions, and then it
appeared to me, and it might just be me, not you,
Mr. Roush, but it appeared to me that you were
saying, well, it's not the system peak demand that
drives the design of a system -- of a circuit, it's
the noncoincident demand. And I'm trying to clear

that up in my own mind.

Do you know, in fact, Mr. Roush, what drives the design of a circuit on a distribution primary circuit?

A. So you're asking me to clarify what demand drives the design of a primary distribution circuit?

Q. Yes.

A. Would be -- and my answer would be that as used in the design of the alternate feed service rates, I'm looking at the peaks on the primary distribution system to determine the rate.

Q. I take it, then, that -- is that on a per-company basis or on the Ohio-AEP companies?

A. The calculations were performed independently for CSP and OP.

Q. Okay. So then if you were to design a new circuit, you would go on the basis of the company noncoincident peak on primary distribution circuits,

is that correct, in designing the capacity of a new
circuit as opposed to the expected capacity demands
to be placed on the circuit you're designing?

EXAMINER BOJKO: Mr. Bell, why don't you
let him answer one of your three questions that you
posed to him.

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481

MR. BELL: I apologize. I'm playing engineer.

EXAMINER BOJKO: Let's back up.

Can you read the first part of Mr. Bell's -- or, Mr. Bell, do you want to break that question down?

MR. BELL: Yes, I will.

EXAMINER BOJKO: That may be easiest.

Q. (By Mr. Bell) You're indicating then, are you not, that it's based -- that it's your belief that the company in designing a new primary distribution circuit builds that circuit based upon the systemwide peak demand for distribution primary circuits; is that correct?

A. No. And I think we're making a disconnect here. My testimony is not talking about designing the circuit. My testimony is talking about taking the costs of those circuits and what's the appropriate basis for unitizing those, and the appropriate basis for unitizing those are the peaks on the primary distribution system.

Q. And it's not the peaks on the circuit that's being designed -- on a particular circuit that's being designed, I take it.

A. It's not based on an individual single circuit. It's based upon average costing just like all of the company's distribution rates are established.

Q. Do you know whether or not circuits are, in fact, designed on that basis?

A. On which basis?

Q. On the basis of the system peak demands for primary distribution circuits. All circuits are based upon that standard -- are constructed based upon that standard, is that your testimony?

EXAMINER BOJKO: Do you know which question you're going to be answering because I'm not sure I know.

Q. Let me back up again.

Are you saying that you use the method you have described for costing the distribution circuits regardless of whether or not that is the basis upon which distribution primary circuits are designed and constructed?

A. I guess what I'm saying is that in the
last cost-of-service studies for Columbus Southern
Power and Ohio Power Company there was a cost
causation allocation basis of how the costs of the
primary distribution system were allocated to
customer classes. Once those costs were assigned to

the customer classes, you have to unitize that to create a rate, and the methodology I've used to unitize that is the demands on the primary distribution system to unitize the costs of the primary distribution system.

In the allocation of primary distribution system costs to the classes, I'm sure if we went back to those cost-of-service studies we would find that some of those costs -- most of those costs were allocated based upon coincident peaks on the distribution system. So I believe I'm being totally consistent with how the costs were allocated in the last case to how they're collected.

Q. Let's move on to the access of interruptible customers to PJM's IRL. Could you tell me, Mr. Roush, in your opinion who has the ownership interest in the load shedding capability of an interruptible customer, the customer who is shedding the IRP load or the supplier who has no obligation to meet that IRP load?

MR. CONWAY: Could I have that question reiterated?

EXAMINER BOJKO: Reiterated or reread?

MR. CONWAY: Reread.

THE WITNESS: Reread, please.

(Record read.)

A. The capability to curtail is a capability of the customer. I'm not sure what ownership interest means so I'm not sure how to answer that part. That's my answer.

Q. Thank you.

With respect to alternate feed and charges proposed for alternate feeds, would you agree, Mr. Roush, that if service on an individual circuit was totally reliable, the customer would have no cause to seek an alternative feed to a second circuit in order to enhance what reliability would otherwise exist?

MR. CONWAY: Objection. The word "totally" is vague, ambiguous. Form of the question is what I'm objecting to, your Honor.

EXAMINER BOJKO: Let's let the witness answer if he can.

A. No.

EXAMINER BOJKO: No, you can't answer, or is the answer no?

THE WITNESS: My answer is no.

EXAMINER BOJKO: Okay.

Q. Would you agree, Mr. Roush, that a customer's desire for an alternative feed to a secondary circuit is more likely than not premised upon a lack of reliability in the service in which the customer's currently being fed?

A. No.

Q. If I am a customer on a circuit that has reliability issues and there are other customers on that circuit, can you identify or can you establish the individual customer that's responsible for a capacity deficiency on the circuit?

A. Your question doesn't make sense to me.

Q. If there are a number of customers on a given circuit and that circuit becomes capacity deficient, is it possible to identify the customer or customers on the circuit that may or may not be responsible for the deficiency?

A. In my mind all of the customers on that circuit would be responsible for the deficiency.

Q. Well --

A. Who would be obligated to improve that circuit to meet their needs --

Q. Could not -- I'm sorry, have you
finished?

A. -- with the exception of an alternate
feed service customer would --

Q. Could not -- I'm sorry, I thought you were finished again.

A. Go ahead.

Q. Can you wave or something and let me know when you're done?

A. Go ahead.

Q. Thank you. If you can say "go ahead" or "I'm done," I'd appreciate it. It will save Mr. Conway from standing up and objecting.

Could not the deficiency on any existing service be the direct result of a lack of maintenance by the company on that given circuit irrespective of the demands placed upon the circuit by all of the customers served thereby?

A. I don't agree with that.

Q. Oh. Would you agree that the portrayal of the increases shown on your DMR exhibit pages 1 of 2 and 2 of 2 are year-over-year increases?

EXAMINER BOJKO: I'm sorry, which DMR exhibit?

MR. BELL: DMR-1, page 1 of 2 and 2 of 2.

EXAMINER BOJKO: Thank you.

A. Yes, I do agree those are year-over-year increases.

Q. For instance, on Columbus & Southern if we were to take the figures shown for the line total, under total increases for 2009 of 238,488,844, the number for 2010 of 302,568,237, and the 347,953,473 for the year 2011, the sum of those figures would reflect a 50 percent increase over the current rate total shown in column 1 of 1,778,632,736, correct?

A. I will accept, subject to check, that you did the math right. But I think we need to clarify again the 2010 and 2011 FAC increases are the maximum increases, not a projection of what those may ultimately turn out to be.

Q. Oh, I'll get to that, believe me, Mr. Roush.

And the same computation could be had for the Ohio Power Company which would, if we were to add the 224,453,990 for the 2009, the 292,573,199 for 2010, and the 336,459,179 for 2011, that would amount to approximately a 50 percent increase over the $1,726,034,005 shown under the Current Rates column, correct?

A. My answer is the same as the prior question, I'll accept your math subject to check. But, again, the FAC increases in '10 and '11 are the maximums, not a projection of what they ultimately will be.

Q. Now, with respect to the 2009 increases, you did append to your testimony, did you not, some typical bill comparisons for only the year 2009 by which customers might be able to approximate the increase for their given service under any given tariff schedule -- rate schedule?

A. I provided typical bill illustrations for 2009 as Exhibit DMR-11.

Q. And would you agree, subject to checking, Mr. Roush, that the percentage increases shown on those typical rate sheets would range for the year 2009 of 9.7 percent to 17 percent, the 9.7 being for Columbus & Southern GS-4 subtransmission being the lowest, and the highest being 17 percent for Columbus & Southern Power residential, as shown on your typical bill comparison?

A. Exhibit DMR-11 for CSP shows a range from 9.7 percent for one particular GS-4 usage level to --

Q. 17.9 percent.

A. -- to 18.1 percent for one particular

GS-3 secondary usage level.

Q. I'm sorry, I missed that. Mine was -- I stand corrected. The print on mine was hard to read.

MR. CONWAY: It's worth waiting for him to complete his answer, isn't it?

Q. I'm sorry, are you done, Mr. Roush?

A. Yes, I am.

Q. Now, as you indicate in your prefiled testimony at page 15, you have not attempted to set forth any tariffs for the years 2010 or for 2011 to avoid creating unnecessary confusion; is that correct?

A. Yes. I have not proposed to file all three sets of tariffs; however, all of the rates that would be contained within this tariff are part of this filing.

Q. If we were to focus upon your DMR-1 exhibit, page 1 of 2 and 2 of 2, would the amounts shown on that exhibit give us an indication of the increases that might be reasonably expected in the out years of 2010 and 2011 as well as the proportional revenue responsibility of the individual customer classes even though you've not shown tariff rate increases for those years by class?

A. I guess I have shown the tariff rates, including the maximum that the FAC could be in my Exhibits DMR-2 and DMR-3, so I think using those rates would be the best way to do that calculation.

Q. Well, let me put it this way, would you agree that fuel costs are a larger component of a large energy-intensive industry than the fuel component would be for a residential customer or customer class?

A. Yes. I would agree in general that for a large high voltage customer fuel is a larger percentage of their total bill.

Q. And would you agree, as reflected in your FAC component for Columbus & Southern Ohio power, and I'm talking now about the first line, that the percentage increases -- that the amount of increases in the FAC of 147.9 million in 2009, $247,612,870 in 2010, and $273,242,516 reflect a total increase in FAC rates of $668,795,063, or an increase over the three years in the fuel costs shown under current rates of 604,035,566 of over a hundred percent increase in those three years?

MR. CONWAY: Objection. It's way too long.

MR. BELL: Well, it may be too long for you, Mr. Conway, but I've got more confidence in the witness.

MR. CONWAY: It's also just mathematics, so it's -- I don't see the point, so relevance to this.

EXAMINER BOJKO: Mr. Roush, if you could answer, that would be wonderful, but if not, we can break it up if you'd like.

THE WITNESS: I will accept Mr. Bell's arithmetic, subject to check. I will again remind Mr. Bell that the 2010 and 2011 FAC increase values are the maximum FAC increase values that were established to stay within the approximate 15 percent guideline, not forecasted FAC.

Q. But the actual responsibility of those energy-intensive customers is far in excess of that hundred percent increase, is it not, to the extent that they will be responsible for that portion in excess of the 15 percent that is capped and recovered in the years 2012 through 2018? Is that not correct, Mr. Roush?

THE WITNESS: Can you read that speech back, please?

(Record read.)

A. I'm not sure that's correct, and I think it goes back to the discussion I had with Ms. Roberts

concerning the workpapers she showed me where it
shows that for CSP the -- I'm sorry, Ms. Grady.

MS. GRADY: Thank you.

THE WITNESS: I apologize, Ms. Grady.

That in the pro forma workpaper that she
showed me, that CSP's FAC increases could either

result in no deferral at all for CSP or result in FAC increases lower than the maximum in 2010 and 2011.

Q. Are you not in this ESP proceeding requesting the Commission authorization to impose increases up to the amounts shown on your DMR-1, page 1 of 2 and 2 of 2, Mr. Roush, whether it be more or less?

THE WITNESS: Can you read that one back?

(Record read.)

EXAMINER BOJKO: I'm looking, you said "up to" first, and then you said "more or less." So could you clarify, Mr. Bell.

Q. Whether the actual revenue requirements of the company under the company's ESP are more, in which event there would be deferred recovery, or less, in which the amounts recovered in those years would be subject to a trueup.

EXAMINER BOJKO: Thank you.

A. With regards to the FAC we're asking for our actual expense during 2009, 2010, 2011, subject to the caveat that if collection of that actual expense results in an increase of greater than approximately 15 percent, that we would defer that increase for subsequent collection.

Q. Thank you, Mr. Roush.

And if I were to ask you the same questions with respect to Ohio Power Company and the FAC component, would your response be the same, and that is, that the actual increases shown in your exhibit for the year 2009, 2010, and 2011 on the FAC line is a hundred percent increase over the current rates as shown on your DMR-1, page 2 of 2?

A. It appears your arithmetic is approximately correct with the same caveat, of course, that's the maximum that's shown in '10 and '11.

Q. And if we were to look at only two of the components on your Exhibits DMR-1, page 1 of 2 and 2 of 2, relating to Columbus & Southern and Ohio Power respectively, would you agree that the vast majority of the increase -- total increase sought in the year 2009 is reflected in the POLR increase and the FAC increase. The roughly 148 million FAC and the 93.6 million POLR charge increase.

THE WITNESS: I'm sorry, could you read that back?

I thought you started with both companies and then shifted to just one.

Q. I'll break it down for simplicity's sake. Would you agree that for Columbus & Southern that of the total increase requested as shown on the total line for 2009 being $238,488,844 total rate increase, that you have represented, the vast majority of that increase is reflected in the roughly $148 million fuel component and the $93 million POLR charge component?

A. Those are the two largest components of the overall increase in 2009 for CSP.

Q. And would the same observation be true with respect to the Ohio Power portrayal, that the FAC and the POLR are the two largest components?

A. No, that would not be the case.

Q. I take that back, I'm sorry. With respect to Ohio Power the two largest components would be the non-FAC environmental capital investment, 84 million, and the 66.6 FAC.

A. The two largest components for Ohio Power would be the FAC and the 2001 to 2008 incremental environmental capital investment.

Q. Now, if the Commission were to be
interested in determining whether or not the ESP plan in the aggregate, that is, over the three years that the company has proposed, should be reviewed, would it be appropriate then, Mr. Roush, to add up the total increases that you have shown under the Total

Increase column for each of the three years for each of the two companies as a starting point?

MR. CONWAY: Your Honor, may I have the question reread?

EXAMINER BOJKO: Please.

MR. BELL: I'll back up again.

Q. Let's take just 2009. The total increases in 2009 are shown at the bottom for each of the companies; are they not? And those increases are all inclusive.

A. With the caveats laid out in my testimony concerning the transmission cost recovery rider and the economic development cost recovery rider, I believe those are the two exceptions, but let me just double check.

Yes, with those two exceptions.

Q. Now, with respect to the increases, the total increases in 2010 and 2011, if one were to attempt to aggregate, if you will, the increases over the three years, wouldn't it be necessary to include the $50 million in POLR charges that will be recovered in 2010, assumingly being recovered in 2010 and 2011 which are not, in fact, increases during the year but revenues recovered during the year, that amount being the current rate POLR for Ohio Power of

39-7 plus 21-2 increase? Those POLR charges are going to be recovered in both 2010 and 2011, are they not?

EXAMINER BOJKO: Mr. Bell, can you let him answer one question before you ask another, please?

A. Let me take the last question first. I believe earlier in your examination we discussed that the 2009 increases, 2010 increases, and 2011 increases shown in Exhibit DMR-1 and DMR-2 are incremental or year over year, so if you start with the Current Rates column, you add the 2009 increases to get what customers would pay in 2009, you add the 2010 increases to get to what customers would pay in 2010, and you add the 2011 increases to get to what customers would pay in 2011, again with the caveat concerning the maximum FAC increase.

Q. Going back then for Columbus & Southern Power on the POLR charge, for instance. If one were

to quantify the aggregate increase in POLR revenue
accruing to the company over the three years, we
would have to take the 93.6 million shown in the 2009
increase and multiply that by 3, would we not, to
represent the total POLR revenue increases over the
three years?

A. Columbus Southern Power Company would see a $93.6 million increase in POLR revenues in all three years '09, '10, and '11.

Q. So in order to determine the effect of your proposal upon the ratepayers, looking only at the POLR charge, we couldn't just look at the $93 million increase in 2009, could we? We'd have to look at the total increase in the POLR revenues over the period of the plan, correct?

A. It really depends on how you're doing your analysis.

Q. Well, if we were to do the analysis in the manner that I'm suggesting, that is, determine the aggregate increase in rates to customers over the three years of the plan, you would do it in the manner that I'm suggesting, would you not, Mr. Roush?

A. I'm not sure, Mr. Bell.

Q. Would the same hold true with respect to the non-FAC component increase of 26 million in 2009,

that that increase would also exist for Columbus &
Southern in the years 2010 and 2011?

A. The Columbus Southern Power
$26 million increase in 2009 for the 2001 to 2008
incremental environmental investment is a one-time
increase in rates in 2009, and the increased level of

those rates would continue in 2010 and 2011.

Q. And the same would hold true with respect to the $84 million for Ohio Power in 2009, would it not? That that $84 million with the additional revenue collected from customers in each of the three years of the plan.

A. The $84 million value for Ohio Power is -- the description of that would be identical to my previous answer.

Q. So that if one were to attempt to quantify, if you will -- I'm sorry, had you finished?

A. Yes, I had.

Q. Okay. So if one were to attempt to quantify the total dollar impact of the company's proposal over the three years of the plan, would you agree that one would have to start with the three-year increase for Columbus & Southern Power as shown under the Total column amounting to something in the order of $978 million and for Ohio Power the

sum of the three figures for each of the years
totaling 852 million, and then one would have to add
the POLR revenues that you and I have just discussed
as well as the non-FAC component revenues for each of
the three years of the plan, would we not, Mr. Roush?

A. Mr. Bell, forgive me, but I'm getting kind of lost in all those numbers because you had quite a few, and I like numbers, but you had quite a few in that one.

Q. All right.

A. Holistically I think if we just keep going back to the concept of current rates are current rates. 2009, the increase there is the increase over current rates, 2010 is the increase over 2009 rates, and 2011 is the increase over 2010 rates, and so however you wish to compare them.

Q. I understand what your exhibits reflect, Mr. Roush. Are you suggesting that it's inappropriate for the Commission to determine in the aggregate the total increase requested by the company as reflected in your exhibits over the entire three years of the plan, as we have just -- as I have just attempted to explore that increase with you?

MR. CONWAY: Objection. The witness has not indicated that any particular viewpoint is inappropriate.

EXAMINER BOJKO: I agree.

Let's let the witness try to now answer that question. I don't think the witness said that before, so let's let the witness answer that question.

THE WITNESS: I'm sorry, can you read it back?

(Record read.)

A. No, I'm not suggesting that in any way, shape, or form, that the Commission should or shouldn't look at anything. I was just struggling with the previous question and example and trying to make sure we were both on the same page as what's contained in the information in my exhibit.

Q. All right. If we were to take Columbus & Southern, for example, and add the total -- and add the three increases in the Total column under your Exhibit DMR-1, would you accept, subject to check, the total increase thus reflected would be 978 million? An approximation.

EXAMINER BOJKO: The total increase for three years over the current rate is what you're asking?

MR. BELL: As shown on his Total line in

his exhibits, not the total that I'm attempting to construct.

EXAMINER BOJKO: Right.

A. What was your number again, Mr. Bell? I apologize.

Q. It's the sum of 238 -- roughly

238.5 million, 302.5 million, and 348 million.

EXAMINER BOJKO: And what did you get when you added -- what was the question based on? What was the number?

MR. RESNIK: It was 978.

MR. BELL: 977.

EXAMINER BOJKO: He was just asking what -- before you agreed he was --

MR. BELL: I thought I gave him the number of 987.

Q. What number did you get?

A. I thought I had it until the boom. I get 889, Mr. Bell.

Q. All right, let's use 889. Let's use your figure so we don't get caught up in my poor math. To which we would have to add the POLR revenue not shown in your exhibit, correct, for the years 2010 and 2011, which would be an additional $186 million.

MR. CONWAY: Objection to the

characterization that the POLR revenue that's being
requested is not shown in the exhibit, because it is.
EXAMINER BOJKO: Well --
MR. BELL: There's a zero for the years
2011 and 2012. That's what I'm trying to get at.
EXAMINER BOJKO: Right. And we're not

getting there very quickly.

Mr. Roush, could you explain to Mr. Bell why there is a zero and how this comes out that the amount -- and how the amount continues and what the zero represents? Let's try that.

THE WITNESS: Sure, be happy to.

I'm almost thinking a picture might be better so I'm going to try to draw one for you with words. But right now the rates collect -- current rates would collect $1.8 million. If we're building a pyramid, in the first year rates would go up 238 million, and that 238 million would continue all three years so there's -- in 2010 you'd add another layer of 302 million, and that 302 million would continue for two years, and then in 2011 there would be an additional 347 million.

So if that visual works, with, again, the maximum FAC caveat that we've been discussing, then the first year increase is 238 million. That

increase would continue for all three years so you
could take that times three. In 2010 the increase is
302.6 million, roughly, for CSP, again, with the
maximum FAC caveat, so you take that times two. And
in 2011 you would take the 348 million, roughly, for
one year, if you were doing what I believe the

arithmetic you're asking to do.
Q. The arithmetic you have just gone through assumes that you have no POLR revenues in 2010 and 2011, do they not?
A. No; that's not correct. It assumes that we have roughly 108 million of POLR revenues in all three years of the ESP.
Q. Oh, your exhibit makes that assumption, that there is 108 million in POLR revenues in each of those two years as opposed -- with the zero total increase that you have shown, I misinterpreted that, and I apologize that it's taken me that long to recognize it.
A. That is the total increase in 2010 over 2011. Over 2009, I'm sorry.
Q. The increase which you have depicted over the three years as shown on your DMR, I think it's clearly understood that that does not include any fuel adjustment clause deferrals; is that correct?

A. Yes. Nothing in Exhibit DMR-1 shows any -- the amounts of any FAC deferrals.

Q. And were you in the hearing room when I believe Mr. Hamrock in response to a question that I posed to him indicated that such deferrals were about 439 million? Does that figure sound correct?

A. I believe there was an illustration in Mr. Assante's testimony. I don't have it now, but that was an illustration assuming 2009 levels of FAC continued for all three years.

Q. You aren't in a position, then, to quantify on your DMR exhibit what the amount of the deferrals are that are not recognized that will be recovered in the years 2012 through 2018.

A. That is not shown in Exhibit DMR-1, I think there are two different locations now that I'm aware of that you could seek such information, the first would --

Q. Where is that, again?

A. The first would be Exhibit LVA-1, which was an illustration of what the deferrals would be assuming the 2009 level of FAC expense continued all three years, so it was purely an illustration.

The second location would be the document I was handed earlier, I believe it's OCC Exhibit 6.

Q. Okay.

A. That showed a line for deferred fuel expense that was in the workpapers for the pro formas filed on October 16th.

Q. And I believe your testimony makes clear on page 4, lines 8 and 9, or 8 through 10, and page

4, line 11, that you have not attempted to quantify the increase in rates ratepayers would experience as a result of changes in -- brought about by the economic development rider, transmission, or other; is that correct?

A. My testimony on this page specifically says I have not estimated "the potential increase resulting from the implementation of the Economic Development Cost Recovery Rider, nor any estimate of future changes in the level of the Companies' existing Transmission Cost Recovery Rider." I think that's all I've addressed there in my testimony.

Q. Do you know whether anyone in the company has made an estimate of what those costs are? I know you have not.

A. To my knowledge I don't know of anybody that's estimated the economic development cost recovery rider, the transmission cost recovery rider we have now filed with this Commission on October

31st, the requested rider level for 2009.

Q. And does that reflect, if you know, an increase? I'm trying to put a whole package together here to give the Commission some indication of what types of increases ratepayers can expect over the period of the ESP. Do you know what --

A. Your question was is the TCRR rider filing that we made on October 31st an increase or a decrease?

Q. Yes.

A. It was a decrease for Columbus Southern Power Company, I believe, and an increase for Ohio Power Company.

Q. In your testimony on page 3 you indicated that you attempted to provide the resulting rate impacts. Focusing on the term "rate impact," Mr. Roush, would you agree that you have not attempted in any way, shape, or form, to evaluate the "affect," a-f-f-e-c-t (sic), of the proposed rates upon households, retail customers, or manufacturers given the current state of the economy, which I believe is generally known to all of us, foreclosure -- home foreclosure rates, highest level in years, unemployment, 16-year high, manufacturing index 26-year low, et cetera, et cetera, et cetera?

MR. CONWAY: Objection.

EXAMINER BOJKO: Grounds?

MR. CONWAY: It assumes facts not in the record. It characterizes circumstances that aren't in the record and asks him to comment on whether or not he's conducted an analysis of the effect of all that, and I think it's burdensome and pointless.

MR. BELL: I think the company's own testimony in this case reflects an awareness of the depressed economic conditions, and my question was simply in referencing --

EXAMINER BOJKO: Whoa. Mr. Bell, how about we strike out all your testimony that we've heard for a couple times now about the exact percentages of the economics surrounding the environment we are living in today and you ask the question in a fashion that merely references the state of the economy, if you'd like to do that.

Q. (By Mr. Bell) I'll rephrase in accordance with the kind suggestion of the Bench. Would you agree, Mr. Roush, that you have not attempted to measure the effect of the dollar increases upon the customers served by Columbus & Southern?

A. I would agree that my testimony in this proceeding is providing the rate impacts on Columbus

Southern Power and Ohio Power customers. I believe Mr. Hamrock in the context of his testimony discussed the company's perspective on achieving other goals of Senate Bill 221, including economic development, energy efficiency, et cetera. So that would have been Mr. Hamrock's testimony. My testimony is specifically the rate impacts.

Q. So Mr. Hamrock is the point man on the effect of the company's revenue increases upon its customers?

A. I guess what I'm saying is, one, he's the boss; two, it was his testimony where he addressed some of these issues.

Q. My point is from your perspective he's the only witness that addressed the precise issue that was the focus of my question?

A. I believe that to be the case.

MR. BELL: Thank you. No further questions.

EXAMINER BOJKO: Mr. White.

MR. WHITE: Just a few questions, your Honor.

- - -

CROSS-EXAMINATION

By Mr. White:

Q. I promise to keep it brief. Mr. Roush, I'm Matt White, and I represent Kroger Company. I just have a few questions for you.

A. Good evening.

Q. Good evening to you.

On page 13 and 14 of your testimony you

discuss the FAC charges; is that correct?
A. Yes, and a little bit onto 15 even.
Q. A little bit onto 15, all right. When AEP was calculating the FAC charges, did they take into account a credit for off-system sales margins to customers?
A. Hopefully that's the same question to Mr. Nelson because he was the better one to answer it. But I believe my understanding of what Mr. Nelson did there was an assignment of costs away from retail customers to off-system sales, but that's kind of my basic understanding of what Mr. Nelson did.
Q. Okay. All these questions are asked with the understanding that there might be other witnesses that have testified to these issues as well, so . . .
Are you aware -- again, Mr. Nelson might be the better witness to have answered that, but I wasn't here for that. But are you aware of the

policies that AEP's affiliates in West Virginia or Virginia, whether or not they give credits for off-system sales margins for fuel-related charges?

MR. CONWAY: Objection, relevance.

MR. WHITE: It's part of his testimony. He discusses the FAC charges and the justification for the FAC charges.

MR. CONWAY: Your Honor, the objection was directed towards the out-of-Ohio part of the question, not the FAC part of the question.

EXAMINER BOJKO: If the witness knows, the witness may answer.

A. I believe Virginia legislation instituted a, I'm going to get the numbers wrong, 75/25 sharing of margins, 75 to customers, 25 to shareholders in the statute in Virginia.

In West Virginia I think margins -- off-system sales margins may be part of the expanded net energy charge there, but I'm not a hundred percent certain of that. Fortunately, I specialize primarily in Ohio, Indiana, Michigan, and Kentucky, so my Virginia, West Virginia knowledge is a little weak.

Q. So were those credits similar to the credits given in Ohio? Would you say customers got more credit in West Virginia and Virginia than they did, from your understanding, than in Ohio?

A. I'm sorry, could you do that one more time for me? I may have just missed the beginning of it.

Q. Are those -- were the credits for

off-system sales margins similar in West Virginia and Virginia, from your understanding, than they were in AEP's application for the FAC charges?

A. I think all three states are different from each other. In fact, I'm not even sure if the margin sharing is part of the Virginia fuel clause or a separate mechanism, so they're all three distinct and different.

Q. Okay.

MR. WHITE: That's all the questions I have, your Honor.

EXAMINER BOJKO: Thank you.

Staff?

MR. MARGARD: Nothing, your Honor. Thank you.

EXAMINER BOJKO: Redirect, Mr. Conway?

MR. CONWAY: Are you prepared for redirect, Mr. Roush?

THE WITNESS: Okay.

MR. RANDAZZO: You can say no.

THE WITNESS: I wouldn't mind taking a real quick break, if that would be okay. Just one minute.

EXAMINER BOJKO: I'll give you five.

THE WITNESS: Thank you, your Honor.

(Discussion off the record.)

EXAMINER BOJKO: Let's go back on the record.

Mr. Conway, do you have any redirect?

MR. CONWAY: Just a few questions, your Honor.

- - -

REDIRECT EXAMINATION

By Mr. Conway:

Q. Mr. Roush, do you recall questions I believe from Mr. Randazzo regarding the circumstances of the companies joining the PJM RTO back in 2000?

A. Actually, in October of 2004.

Q. I'm sorry.

A. Yes.

Q. Thank you for that correction.

What is your understanding of how promptly the AEP companies raised their concerns regarding the ability of retail customers to

participate in the PJM DR programs upon their joining
the RTO?

A. The companies raised the issue basically
when the first customer attempted to sign up, and
even prior to that it was our belief that the current
tariff provisions that restricted sales for resale

protected the companies and addressed that issue. So basically from day one.

Q. Those tariff provisions were in the companies' tariffs at the time they joined the RTO?

A. Yes, they were in the tariffs when we joined the RTO. And specifically in my testimony I addressed on lines 20 through 23 of my testimony --

EXAMINER BOJKO: Page 7?

MR. RANDAZZO: What page is that, please?

A. -- of page 7 what I just stated, which is that we believe our existing Ts & Cs address the issue.

Q. Mr. Roush, have the companies raised their concern regarding participation by retail customers in PJM demand response programs on a consistent basis since they joined the RTO?

A. Yes. We've raised our concern pretty much at every opportunity we've had.

Q. Mr. Roush, do you also recall some

questions also I believe from Mr. Randazzo regarding the operation of the FAC after the three-year term of the proposed electric security plan that is before the Commission in this proceeding?

A. Yes, I remember those questions.

Q. And how do you envision the FAC operating after the end of the three-year ESP?

A. I think, again, going back in my testimony to the top of page 15, my expectation was that it would operate in a traditional manner beginning in 2012, and I think that is consistent whether the company comes back and files an ESP for that period or an MRO for that period. It would also just be dependent on what percentage of the MRO is at market, how the FAC might operate in synchronicity with that.

Q. And so if it were to be an MRO that the company enters into after the end of the ESP, the FAC would still be in operation with regard to the portion of the load that's not being served by the competitively bid purchased power supplies?

MR. RANDAZZO: I object. Leading.

MR. CONWAY: It's 6:15, your Honor.

EXAMINER BOJKO: Can you rephrase, please?

MR. CONWAY: Yes, your Honor.

Q. Could you explain what you mean by "synchronicity"?

A. Certainly. Under an MRO, unless it was a complete move a hundred percent to market, there would be some percentage at the competitive bid, some percentage that would not be at the competitive bid, and the traditional FAC component I think would still apply to the noncompetitive bid percentage.

Q. Do you recall questions regarding the recovery of the FAC cost deferrals during the 2012-2018 period which would be after the three-year term of the ESP? Do you recall that?

A. Yes, I remember that.

Q. And what is your understanding of the basis for the companies' request to recover those deferred costs during the 2012-2018 period, which is after the ESP period?

A. My basic understanding was that the nonlegal person's reading of the statute was that it allowed for phase-ins, and that's specifically what that nonbypassable rider is addressing.

MR. CONWAY: Thank you, Mr. Roush.

That's all I have, your Honor.

EXAMINER BOJKO: Thank you.

Any recross based on what just was said?
Mr. Smalz?
MR. SMALZ: No, your Honor.
EXAMINER BOJKO: Mr. O'Brien?
Staff.
MR. MARGARD: No.

MR. SETTINERI: No, your Honor.

MS. GRADY: No, your Honor.

EXAMINER BOJKO: Mr. Randazzo?

MR. RANDAZZO: Yes, just a couple questions. Sorry.

\- - -

RECROSS-EXAMINATION

By Mr. Randazzo:

Q. Mr. Roush, with regard to AEP's efforts on the PJM demand response programs that you referred to in your answers, I had thought previously when we talked about this subject that you agreed that those programs were part of PJM's tariff when AEP joined PJM. Am I correct that those programs were part of PJM's tariff when AEP joined PJM?

A. If my memory serves me correctly, I believe only the economic program was in effect, and at the time we joined PJM what I stated was that our belief was since the economic program was a sale for resale, that our tariff prohibition in our retail tariffs prohibiting sales for resale would have precluded our customers from participating.

Q. Okay. And are you aware of any language that was in Senate Bill 3, the predecessor to Senate Bill 221, that prohibits any unreasonable restrictions on sales for resale?

A. I don't recall.

Q. Did you ask counsel whether or not there was anything in either Senate Bill 221 or Senate Bill 3 that would affect the language in your terms and conditions of your tariff with regard to sales for resale?

A. I didn't specifically ask counsel that question.

Q. If you had programs that AEP operated, demand response programs, wouldn't that be a sale for resale?

A. No, that's not my understanding.

Q. Why not?

A. My understanding of a sale for resale is that AEP-Ohio would be selling the power to the customer under its retail tariffs and then the customer is selling the power to PJM and/or their curtailment service provider under the FERC wholesale tariff. In my view an AEP-Ohio program, both sides of that program, are retail programs, not a hybrid of retail and wholesale.

Q. Well, let's talk about your price curtailable service. Isn't that a sale for resale? When a customer releases capacity back to AEP for a stated price, is it a sale to keep it?

A. First, I don't agree that it's a release of capacity. Second, I stand by my previous answer, I don't view that as a sale for resale.

Q. I see. But you're not aware of anything in Senate Bill 3 that might have affected provisions in tariffs dealing with sale for resale; is that correct?

A. I don't recall anything. The only thing I can recall is that our existing tariffs that are in effect still have that prohibition in them.

Q. All right. Now, with regard to the continuation of the fuel adjustment clause beyond the term of the ESP, are you proposing that it would be nonbypassable?

A. The fuel adjustment clause?

Q. Yes.

A. Not to my knowledge.

Q. So if a customer was shopping and you had an MRO, you would be able to avoid entirely the fuel adjustment clause?

EXAMINER BOJKO: You would?

MR. RANDAZZO: You would, yes.

A. I believe that would be the case, but -- well, clearly, the company hasn't put together an MRO filing for 2012 at this time.

Q. Okay. The amount that's deferred and recovered through the FAC mechanism in the period beginning 2012 is nonbypassable, is it not, according to your proposal?

A. The deferred FAC expense would be collected through a nonbypassable rider under the company's proposed ESP.

Q. And would that be -- the nonbypassable rider, would that be confined to only that portion of an MRO that is not competitively bid?

A. Again, my view of the definition of nonbypassable is nonbypassable for all customers.

Q. Well, if -- strike that.

Would the FAC that continues beyond the three-year proposed term of the ESP include the same elements that are in the FAC during the term of the ESP?

A. Again, my expectation is that the FAC beginning in 2012 will be effectively the FAC as proposed by the companies in this ESP without the phase-in component. But, like I said earlier, until the company files an ESP or MRO for 2012 and beyond, I can't say with a hundred percent certainty.

Q. Okay. Here's the problem that I have, sir. In order to accept the ESP, the Commission has to determine that the ESP in the aggregate is greater -- is better for customers than the alternative MRO. Is that your understanding?

A. I think that's a general standard that's within the legislation.

Q. And as you've proposed it, we have an amortization of deferrals that continue beyond the term of the ESP you proposed commencing in 2012, and we have an FAC that you've characterized as operating traditionally beginning in 2012 and beyond. What values do we attribute to those mechanisms for purposes of comparing your ESP to what would otherwise happen under the MRO?

A. I guess I'm struggling with how to advise you to do your analysis. In my view the FAC operating in a traditional manner beginning in 2012, I guess I don't see there any numeric value to attribute to that as far as evaluating the company's

ESP. And then as far as the nonbypassable rider in 2012 to 2018, I believe you would use the projections that the companies filed in their pro formas to evaluate what that deferral is.

Q. Okay. But it would be appropriate for purposes of the comparison to consider the effect of the amortization of deferrals in the period 2012 and beyond, plus whatever numeric value might be appropriate for the continuation of the FAC beyond -- in 2012 and beyond for purposes of comparing your proposed ESP to the MRO. In other words, you'd consider the effect of those two things for purposes of evaluating the MRO alternative, right?

A. I don't know. I don't know. The second one in particular I'm not sure. The first one, I mean, I think the Commission's going to make whatever evaluation the Commission's going to make, so I don't know.

Q. Do you know whether AEP has considered the effects of those two things for purposes of conducting its analysis of the MRO?

A. I seem to recall some discussion of the phase-in in Mr. Baker's testimony.

Q. Do you know, sir? This is not a "do you recall anything about this." I asked you do you know.

A. I know that Mr. Baker had a discussion regarding the phase-in in his testimony so I think he would be the best one to address that.

Q. Okay.

MR. RANDAZZO: Thank you.

EXAMINER BOJKO: Ms. Wung?

MS. WUNG: No questions your Honor.

EXAMINER BOJKO: Mr. Rinebolt.

MR. RINEBOLT: No questions.

EXAMINER BOJKO: Mr. Boehm.

MR. BOEHM: (Shakes head.)

EXAMINER BOJKO: Mr. Bell.

MR. BELL: No.

EXAMINER BOJKO: Mr. White?

MR. WHITE: I have no questions.

EXAMINER BOJKO: I have a few questions. Mr. Conway.

MR. CONWAY: I'm sorry, did you say you have a few questions?

EXAMINER BOJKO: I do have a few questions.

\- - -

EXAMINATION

By Examiner Bojko:

Q. Mr. Roush, thank you for answering my
questions that I asked earlier of Mr. Earl about line
extensions and premium service in one of your
answers. I appreciate that.

A. You're welcome.

Q. Now I would like to direct you to page 8 of your testimony, and I think you said two things that I just want to make sure that the record's clear on the AFS.

I thought you said at one point that the AFS was done by special contract addendums, and then I thought you also said that it was done pursuant to a tariff. So I'm a little concerned about -- I know there's a new tariff provision being requested, but what is the current state of an AFS service?

A. I'm sorry, I didn't mean to interrupt. In the company's terms and conditions of service, I think it's for CSP's item No. 17 in the Ts & Cs, that's basically the basis for our authority to enter into the special contracts. So --

Q. So it specifically says AFS -- for AFS you can join the special contracts? I thought you said something earlier about a unique arrangement.

A. Yeah. It's a more general set of language. Temporary and special service is the provision.

Q. So you interpret that language to mean AFS only, or could there be other services that fall under that category?

A. There's lots of other things in there, but I believe what I was asked was specifically where in our tariffs did it authorize us to enter into these special agreements, and that was the -- that language was the springboard for the entering into the special agreements for AFS.

Q. Okay. So with that understanding, then, when you calculated your OHA Exhibit 2, you went back to the last rate case, did you calculate that based on the special contract addendums that you knew of, or was it calculated on the general concept of the terms and conditions of unique circumstances in your tariff provision that you just told me about?

A. I think the answer to that question is yes to both. These calculations were actually done quite a few years ago when the circumstance came up with certain customers concerning AFS. So these rates are the rates that are included in those special agreements currently, and all we're doing is incorporating them into a tariff to make it much more transparent.

Q. And that would be specific to AFS
service, you can distinguish -- you can tell what is
a contract addendum for AFS service.

A. Absolutely.

Q. Okay. Well, I guess the next logical
question, the special contract addendums would be

either the same as those entered into in the '94 or the '91 cases, or they were continued contract addendums?

A. I think most of them that were entered into after the '91 and '94 cases, the rates were designed based on the final values out of the '91 and '94 case, and we've been entering into agreements pretty much I think off and on since then for at least the past seven or eight years, I believe. And all of the agreements would have been based on the costs underlying this. Not all of them are standard AFS. Some of them have some unique arrangements where instead of having redundant primary circuit and primary line -- primary transformer, they might just have one piece, in which case you have to break the rate out further.

Q. If you look at page 9 and 10 of your testimony --

A. Yes.

Q. -- you talk about the riders that exist today and you talk about how the company is proposing that the tax-related riders will be put into the distribution rate, and then I believe you talk about the PAR rider and the GCR rider will be put into base generation rates; is that right? And I believe that's reflective of DMR-2 and 3.

A. DMR-2 and DMR-3 show how I roll those in. We just carry over from the ETP cases and the RSP case. We just kind of -- the legacy of a whole bunch of riders that were not really tracking riders but were just kind of established riders, but the concept was to just eliminate as many of those as possible, roll them into generation rates, base generation rates, base distribution rates.

Q. So with regard to the PAR rider --

A. That's one that's confusing, or at least by some. Maybe you've got it cold. I'm sorry.

Q. My question is, then, under the company's proposal the customers that used to be Mon Power customers will be still paying the standard service offer rate, right?

A. Of CSP, yes.

Q. Of CSP. And currently my understanding of the PAR rider is any delta from the RFP that was conducted to serve those customers is what flows through the PAR rider. Any delta revenue from the current SSO -- I'm sorry. I'm trying to hurry. The current SSO rate versus the RFP rate that was established, that's what is in the PAR currently; is that right?

A. Yes, that's correct.

Q. Go ahead.

A. What we're doing with the PAR is saying that PAR revenue -- effectively what Mr. Nelson did was say that is part of existing FAC, and so we said that part is current FAC, so when we're looking at proposed FAC, there's the expense of that purchase on the current side and then the expense of the 5, 10, 15 on the proposed side.

Q. Is it the company's proposal that power will continue to need to be purchased for those select customers?

A. I guess the existing purchases all go away at the end of '08. And then I think Mr. Baker -- and I hate to punt to him -- but Mr. Baker talks about the rationale for making those 5, 10, 15 purchases, part of which is because of Mon Power.

Q. But your proposal, putting the 5, 10, 15 aside, you wouldn't carry a PAR in the future that would reflect some kind of delta versus the purchases in the standard service offer that is --

A. Absolutely correct. There would be no delta rider in the company's proposed ESP related to Mon Power. We're simply saying that purchase today, the revenues go in fuel. In the future we're not asking for any type of delta.

Q. Remind me again the 5, 10, and 15 percent that you just referenced, that's just not -- or the rationale isn't just for the former Mon Power customers, is it?

A. No. I think Mr. Baker talks about that and Ormet, and I think some other things as well.

Q. On page 14 there was a lot of discussion about the FAC periodic filings, and you made reference to you would view for what I'll call a trueup, you would view the FAC in a given period of time, and then my understanding from your cross-examination responses, the company doesn't really have a proposed given period of time. You're just assuming that the Commission will make it quarterly as other FAC is today and as I think, what you said, our rules -- our rules that were recently adopted state that those filings will be made on a quarterly basis; is that right?

A. Yeah. When we filed, we expected some type of periodicity within the rules, and the rules I believe do say quarterly.

Q. But you didn't have a specific period. You weren't requesting a specific period in your

application.
A. No. We expected to follow the Commission's rules.
Q. Good answer.
I have a couple more that were punted to you throughout the course of our hearing. This was punted to either Mr. Baker or yourself, so I'm not sure if it's you or Mr. Baker.
But what is AEP's actual proposal? If you have to go out and purchase power when a customer returns after shopping, would that flow through the FAC? Would the cost to procure?
A. I believe the cost of any purchased power that gets assigned to retail would flow through the FAC. Now, I think conceptually there's maybe a stacking problem there in that if a customer returned, the --
Q. From the power pool you're talking about?
A. Exactly. There may be a stacking problem

there in that if the customer returns to us from
shopping and we have to go out and procure power,
say, in the short-term market for that, that power
may end up getting assigned off-system instead of
being assigned to retail, because I don't think
there's a direct assignment mechanism. So . . .

Q. But in any respect, you think that if there are any incremental costs, that they would have to flow through the FAC component.

A. Yes, I think any purchased power has to go into that calculation of the FAC. I'm just not sure if it's, at least I don't believe it's a direct dollar-for-dollar assignment kind of thing in that circumstance. As far as that, I can say, well, this customer came back. I had to go buy this expensive power and I'm going to assign that to retail. I don't think that's the way Mr. Nelson's allocations work.

Q. And, Mr. Roush, you're responsible for the tariffs that I think we've discussed previously in this hearing over the last week or two, that the tariffs currently in effect expire at the end of 2008; is that right?

A. Yes, they have language generally in the availability that says this tariff will remain in effect through like December 31, '08.

Q. And page 15 of your testimony on lines 7 through 17 you explain a little bit about compliance filings and what happens -- what has to happen. But AEP will have to file new tariffs prior to the end of the year, right?

A. That's something we're trying to figure out how to deal with. You're absolutely correct. You know, whether it's file new tariffs that simply strike that sentence from all of the appropriate places or what we do, I'm just not sure because --

Q. Well, given that it's December 1st, would that have to be done relatively quickly?

A. Yes.

Q. How long does the company usually file new tariffs before they take effect? How long do you usually file before they become effective?

A. It varies. Sometimes as short as the same day or the next day; sometimes there's like a ten-day notice type period where we have to get approval of bill notices with the staff, et cetera. So it varies. I mean, we've filed tariffs as short as like a day or so, but that's usually after the Commission's issued some type of order telling us to file them, so this is kind of a little different.

Q. Putting bill format aside and bill
notices --

A. Sorry.

Q. -- you would guess in the circumstance
that's before us that you would have to have some
kind of Commission approval of new tariffs; is that

what you anticipate? Or is that your expectation? Or hope?

A. I think so, but I haven't spent a lot of time beating on my attorneys to help me answer that one, but I think that we'd either have to have some type of a direction from the Commission to say "file them," or we'd have to file them and get approval, one way or the other, which, like you said, doesn't leave us a lot of time.

EXAMINER BOJKO: That's all I have, Mr. Roush. Thank you.

THE WITNESS: Sorry I couldn't be clearer on that last answer.

EXAMINER BOJKO: No.

Yes, Mr. Conway.

MR. CONWAY: Your Honor, I would move for the admission of Company's Exhibit No. 1, which is Mr. Roush's prefiled direct testimony along with his exhibits DMR-1 through 11.

EXAMINER BOJKO: Any opposition to the admission of Mr. Roush's testimony, which was -- I believe it was initially marked for identification purposes or introduced on the first day of hearing, November 17th. Any opposition to that?

Hearing none, it will be admitted.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER BOJKO: Mr. O'Brien.

MR. O'BRIEN: Your Honor, I would move the admission of OHA Exhibit No. 2 into the record, please.

EXAMINER BOJKO: Any opposition to the admission of OHA's Exhibit 2 which is interrogatory No. 1-5?

MR. CONWAY: No, your Honor.

EXAMINER BOJKO: It will be so admitted.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER BOJKO: We will reconvene tomorrow at 9 a.m. Thank you.

(The hearing concluded at 6:44 p.m.)

\- - -

CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Monday, December 1, 2008, and carefully compared with my original stenographic notes.

____

Maria DiPaolo Jones, Registered
Diplomate Reporter, CRR and Notary
Public in and for the State of
Ohio.

(MDJ-3306)

\- - -

ARMSTRONG & OKEY, INC., Columbus, Ohio (614) 224-9481