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Missouri Public
Service Commission

DEPOSITION OF MICHAEL S. PROCTOR

BEFORE THE PUBLIC SERVICE COMMISSION
STATE OF MISSOURI

THE STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION,	)	
Complainant,	)	Case No. EC-2002-1
vs.	)	
UNION ELECTRIC COMPANY, d/b/a AMERENUE,	)	
Respondent.	)	

DEPOSITION OF MICHAEL S. PROCTOR, Ph.D.
TAKEN ON BEHALF OF THE RESPONDENT
APRIL 17, 2002

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UNION ELECTRIC COMPANY, d/b/a AMERENUE,	)	
Respondent.	)	April 17, 2002
	)	Jefferson City, MO

DEPOSITION OF MICHAEL S. PROCTOR, Ph.D., a witness, sworn and examined on the 17th day of April, 2002, between the hours of 8:00 a.m. and 6:00 p.m. of that day at the Missouri Public Service Commission, Room 210, Governor State Office Building, in the City of Jefferson, County of Cole, State of Missouri, before

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Notary Public, within and for the State of Missouri, in the above-entitled cause, on the part of the Respondent, taken pursuant to agreement.

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Leon Bender, PSC Staff
Lena Mantle, PSC Staff
Ryan Kind, OPC Staff
Rick Voytas, Ameren
Johannes P. Pfeifenberger, The Brattle Group
Kathleen C. McShane, CFA, Foster Associates, Incorporated

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MICHAEL S. PROCTOR, Ph.D., being duly sworn, testified as follows:

DIRECT EXAMINATION BY MR. RAYBUCK:

Q. Good morning, Dr. Proctor.

A. Good morning.

Q. My name is Joseph Raybuck. I'm an attorney with AmerenUE, and I'm going to be asking you some questions this morning about your March 1st testimony.

Would you please begin by stating your name for the record?

A. My name is Michael S. Proctor.

Q. And what is your position with the Public Service Commission?

A. I am Manager of Economic Analysis.

Q. Have you ever had your deposition taken before?

A. Yes.

Q. Okay. Let me go over a couple of ground rules which will probably be self-evident to you.

Basically, if you don't understand any of my questions, please let me know. If you don't say anything, I'll assume that you understand my questions --

A. Okay.

Q. -- fair enough?

And I'm going to attempt to avoid references to confidential material. My preference is to keep this completely none confidential material. However if I stumble into this area or you feel you need to provide confidential information in your answer, please let me know and we'll take the appropriate cautions.

A. Okay.

MR. RAYBUCK: If you need to take a break at any time, please feel free to do so.

I'd like now to go around the room and ask everyone to identify themselves by name and position. Johannes, would you start, please?

MR. PFEIFENBERGER: My name is Johannes Pfeifenberger. I'm with the Brattle Group. We are consultants to Ameren.

MR. KIND: My name is Ryan Kind. I'm a Chief Energy Economist at the Missouri Office of the Public Counsel.

MR. ZUCKER: Rick Zucker, Z-u-c-k-e-r, Assistant General Counsel with Laclede Gas Company.

MS. LANGENECKERT: Lisa Langeneckert. I'm attorney for the Missouri Energy Group.

MR. MOLTENI: Ronald Molteni with the Attorney General's Office.

MR. Meyer: Greg Meyer with the Commission Staff.

MR. BENDER: Leon Bender, Commission Staff.

MR. DOTTHEIM: Steve Dottheim. I'm an attorney with the Public Service Commission.

MS. MANTLE: Lena Mantle with the Missouri Public Service Commission Staff.

MR. VOYTAS: Rick Voytas with Ameren.

MR. CYNKAR: Bob Cynkar with Cooper and Kirk, counsel for Ameren.

BY MR. RAYBUCK:

Q. Dr. Proctor, I understand you have some corrections to your testimony that you would like to make and an additional work paper you would like to make us aware of?

A. Yes. On page 16 of my testimony at line 16, the sentence reads that -- about monthly documents that were received from the Staff, and it should have read received from UE.

Q. Okay.

A. And a little further down on that same page, line 20, "admissions," possessive, "allowances" just should be emission allowances. Those are the corrections in the testimony.

When I was going through the -- putting the work papers together for this deposition, I realized or -- that I had provided a wrong work paper, one that is entitled, Energy Cost Allocations. It's from a different case. I'm not sure how it got in this set, but did not provide work papers related to schedule 5 of my testimony on fixed O&M expenses, and I have those with me today. And I will give you both an electronic and a paper copy, of course.

Q. Thank you.

A. I have a couple of the other copies for other folks that are interested in those.

Q. Now, if I understand what you've handed me, these are the work papers which supported your schedule 5?

A. That's correct.

Q. And what you had provided with your March 1st testimony to support schedule 5 went with a different case?

A. Yes. It was the wrong -- wrong work paper.

Q. Let me just take a look at schedule 5 so I can make sure I understand what you're referring to.

Did you make any changes to your schedule 5?

A. No.

Q. Okay. Just -- you're just providing the work papers that go along with it?

A. The work papers that back up schedule 5, that's correct.
Q. Did you have any other corrections or comments to make?
A. Not at this time, no.
Q. Okay. You indicated that you were -- you are the Manager of the Economic Analysis Group?
A. That's correct.
Q. And who do you report to?
A. Warren Wood.
Q. And did you discuss your March 1st testimony with Mr. Wood before it was filed?
A. Mr. Wood reviewed that testimony before it was filed, yes.
Q. And did you have any discussions with him about that testimony?
A. Not that I can recall.
Q. Okay. And did others at the Staff, aside from your attorney -- I'm not asking you to talk about any attorney/client discussions. But did you have discussions with others at the Staff about your testimony before it was filed?
A. Yes. I discussed that -- that testimony with Mr. Meyer, Greg Meyer. I discussed that testimony, not in great detail, but to some extent

with Bob Schallenberg, the Division Director.

Q. Okay. Any other persons at the Staff or at the Commission?

A. In terms of the specific testimony, no.

Q. Okay. Were there any persons outside of the Commission with whom you discussed your March 1st testimony before it was filed?

A. No.

Q. On page 2 at line 14 you reference the work you've done on regional transmission organizations, or RTOs for short.

A. Yes.

Q. Are you familiar with Mr. Cassidy's March 1st testimony?

A. Yes, I am.

Q. And you probably recall that in that testimony he recommended the disallowance of about 12-and-a-half-million dollars paid by Ameren to leave the Midwest ISO?

A. That's correct.

Q. And did you have discussions with Mr. Cassidy regarding Ameren's decision to leave the Midwest ISO?

A. I had discussions with Mr. Cassidy regarding the status of where the whole RTO picture was at that point as of March 1st. I don't know that we discussed in any detail Ameren's decision to leave --

Q. Did you discuss with -- excuse me. Go ahead.

A. -- to leave the Midwest ISO.

Q. Okay. Did you discuss with Mr. Cassidy whether it was likely that Ameren would rejoin the Midwest ISO?

A. Yes, I did.

Q. And what generally did you discuss with him?

A. Well, at that time, March 1st, the indications were that the Alliance -- the Alliance group of utilities were -- or had reached an agreement with Midwest ISO by which they would join the -- rejoin -- or join the Midwest ISO as an independent transmission company.

Q. By the way, Alliance is with a capital A; is that correct?

A. Yes, that's correct.

Q. So you had discussions, I take it, with Mr. Cassidy about the possibility of Ameren rejoining the Midwest ISO in some form?

A. In some form, that's correct. At that time the form was as a member of the Alliance companies and as -- in that group being an independent transmission company under the Midwest ISO umbrella.

Q. Okay. Is it your belief that if Ameren rejoins the Midwest ISO under any configuration, whether it's part of the Alliance or in some other fashion, that Ameren will recover its 12-and-a-half-million-dollar exit fee?

A. That's a possibility. At the time, March 1st, that was the indication. Subsequent to that, at the time that both the Alliance companies and the Midwest ISO filed with the FERC, which I -- was mid-March; I think it was the 18th of March -- apparently, the negotiations had -- had broken down and there was some difficulties in resolving that, so -- so there is a possibility that they may not recover that --

Q. Okay.

A. -- those dollars.

Q. Do you know whether Ameren would need a FERC order to require the Midwest ISO to give back the 12-and-a-half-million dollars to UE, or to Ameren?

A. I don't know if it's required, but what I would imagine would happen is if -- if the Alliance companies and Midwest ISO reached an agreement, part of that agreement would be -- would involve whether those dollars would get paid back or not. That agreement would be submitted to the FERC, who would then approve it or not approve it. So I'm sure there will be a FERC approval involved in the process.

It may be that they can't reach agreement. They go to FERC. In fact, the Alliance companies have asked FERC at this point to make a decision about some of the issues that are unresolved in their negotiations.

Q. Okay.

A. And that would be one of the issues that FERC would decide.

Q. Okay. Would it be fair to say that there is no certainty that Ameren will recover the 12-and-a-half million dollars?

A. I would agree with that. There is no certainty.

Q. Assuming -- well, do you think it is likely that -- well, let's assume Ameren is going to rejoin the Midwest ISO.

A. Okay.

Q. Do you think that's a reasonable assumption to make?

A. I think it's a reasonable assumption at this time, yes.

Q. Well, making that assumption, do you know whether Ameren is likely to incur costs in the future as a member of the Midwest ISO in some fashion?

A. In some fashion, they will.

Q. Okay. What costs, if any, are you aware of that Ameren is going to incur, assuming it's a member of the Midwest ISO?

A. I haven't sat down and detailed out those costs. In fact, what those costs are is a subject of the negotiations and a subject of disagreement between the Midwest ISO and the Alliance companies.

The Alliance companies want the Midwest ISO to unbundle the costs of its services and, as an ITC, buy just those services that it needs, and so those would be the costs that they would incur. And in that case, the Midwest ISO is of the position that they would not refund the payment that's been made. And that's part of the disagreement right now.

So I don't know the specifics of the costs. It would depend upon how they come in and what FERC decides about whether they are going to allow them to unbundle costs or --

Q. Okay. Let me ask you about the MISO schedule 10. Are you familiar with that?

A. Would you describe it to me a little bit. I don't -- not by the name schedule 10.

Q. Well, as I understand it, it is an administrative charge imposed on transmission users --
A. Oh, okay.
Q. -- to pay for the Midwest ISO's operations.
A. Yes, I'm familiar with that.
Q. Are you familiar with the magnitude of that cost or charge?
A. I think it's 15 cents a megawatt hour.
Q. And do you know if that -- whether it's going to be any less than 15 cents in the future, in the near future?
A. In the near future, I'm not sure.
Q. Okay. But currently it's set at 15 cents per megawatt hour?
A. That's my understanding, yes.
Q. And assuming Ameren joins the Midwest ISO, that would be a charge imposed on Ameren, would it not?
A. Again, it depends -- that 15-cent charge may be unbundled to different service components, so if -- if, for example, Ameren stays a part of Alliance, and Alliance joins the Midwest ISO, and it performs certain functions and doesn't need those functions from the Midwest ISO, and the Midwest ISO's functions, services, are unbundled, then the Alliance companies

may not pay the full 15 cents. They may only pay a portion of it.

Q. Okay. I'm going to ask you some questions now about the Joint Dispatch Agreement.

A. Okay.

Q. And for abbreviation's sake, we'll refer to that as the JDA.

A. Okay.

Q. Now, in response to your data requests, you provided a copy of the JDA dated May 1, 2000. Correct?

A. I believe that's correct.

Q. And do you have that in your hands now?

A. Yes.

Q. And according to the title page, this is an agreement between Union Electric Company, or UE for short, Central Illinois Public Service Company, or C-I-P-S, or CIPS for short, and Ameren Energy Generating Company, or AEG for short?

A. That's correct.

Q. Those are the parties to the agreement.

And do you -- do you know -- is it your understanding that AEG is an exempt wholesale generator?

A. That's my understanding, yes.

Q. And do you know whether EWG is allowed to sell at retail?

A. My understanding is that they are not.

Q. Okay. Now, what is your understanding as to Ameren Energy Marketing Company, or AEM for short?

A. My understanding of Ameren Energy Marketing Company is that it was established when the state of Illinois went to retail competition, and it was established in order that it may -- might compete in making retail sales because the Ameren Energy Generation Company could not do that.

Further, that was my understanding of why it was established at the time, is that -- is that PUHCA did not allow for the generation -- the EWG to make retail sales, so the marketing company was set up to do that.

Q. By PUHCA, you mean P-U-H-C-A?

A. Sorry. But subsequent to that, became aware that AEM is also in the business of making wholesale sales as well on behalf of AEG.

Q. And do you know whether AEM has obtained authority from the Federal Energy Regulatory Commission, or FERC, to sell electricity at wholesale or market rates?

A. Yes, they have.

Q. It's your understanding they have obtained --

A. Yes.

Q. -- that FERC authority?

A. That's my understanding.

Q. Okay. Do you know any of the wholesale or resale customers of AEM?

A. The only -- let me back up.

I know that Union Electric has been a wholesale customer. My recollection from -- that's the only wholesale customer that I can think of at this point.

Q. What about retail customers? Do you know who their retail customers, if any, might be?

A. Not -- not in terms of the specifics. I know that there is some kind of contract with Soyland. I'm not -- that's out -- outside of the -- that area, but, no, I haven't -- I haven't gone through a list of their retail customers.

Q. Okay. Is it your understanding that Soyland is a retail customer, or do you know?

A. That -- well, that was my understanding, but --

Q. Okay.

A. I'm not sure whether they are retail or wholesale. Since they are a retail business, I would assume they are a retail customer.

Q. Do you know when the JDA began?

A. It began shortly after the Commission -- after the merger of the two companies was approved.

Q. The "two companies" being UE and CIPS?

A. And CIPS, yes.

Probably somewhere around 1996 or '97, but I'm not -- I don't know the specific month.

Q. Okay. Well, it began as a result of the merger of UE and CIPS?

A. That's correct.

Q. And after UE and CIPS had obtained all regulatory approval, is it your understanding that the JDA commenced?

A. That's correct.

Q. And do you know why UE and CIPS wanted to have a JDA?

A. Yes. And this is very typical of all merger filings, that one of the benefits from -- from merging two companies is to gain increased efficiencies through the joint dispatch of the generation and other resources that each company has.

Q. And can you elaborate on how those efficiencies would result from the JDA?

A. Generally, probably one of the greatest efficiencies that -- that would occur is in unit commitment that occurs the day ahead. You can -- you can more efficiently commit those units for -- for what you expect the load to be the next day.

Potentially, another advantage from it is -- is fuel savings that you would get at cost, so you would transfer -- transfer generation from one resource to meet the load of the other -- of the other company.

Q. Any other --

A. Those are the primary two benefits, I believe.

Q. Going back to the first one you mentioned, the efficiencies resulting from committing a unit on a day-ahead basis --

A. Yes.

Q. -- if I understand what you're referring to, on a day-ahead basis, the company would make some sort of determination as to what the load was going to be the next day --

A. Correct.

Q. -- whether it was going to be a hot summer day or a cool autumn day --

A. That's correct.

Q. -- and make a decision as to which units would be needed to satisfy the day ahead -- the load the next day?

A. That's correct.

Q. And if you had a larger fleet of generating units, you could obtain some efficiencies in terms of the selection of the units that would be used. Is that what you're referring to?

A. If you were -- if you were meeting a load separately, or, let's say, on a stand-alone basis, you might not shut down a unit -- unit commitment decision is about either starting up or shutting down units that have -- that have long starting costs -- not costs, but -- they have some start-up costs, but they have -- it takes several hours for them to come on line. You can't just turn them on instantaneously. They have a ramp-up rate.

So you may make a decision, for example, if you were CIPS to leave a unit on that's a higher cost unit; whereas, when you're putting those together, you would actually turn that unit off or not start it up because -- and leave the Union Electric unit on instead.

Q. So the JDA would allow you to avoid incurring these start-up costs --

A. That's correct.
Q. -- and turn-off costs, if you will?
A. Right.
Q. And with regard to fuel savings at cost --
A. Uh-huh.
Q. -- can you elaborate for me how that would be a benefit as compared to what a stand-alone company would incur for fuel costs?
A. I might -- yes, I can. And I've got to put it into a context of when -- when the Joint Dispatch Agreement went into effect. And since then the wholesale market has changed significantly and is due to change again very dramatically in the near future, so -- and a lot of the savings in my mind is linked to the structure of the wholesale market.
Now, if you were -- if you were looking at this on a -- as if these two entities, these two companies were an island, there was -- there was nobody else, then there would probably be no savings from the JDA. Now, what there would be is some kind of profit sharing that occurs because they would sell -- buy and sell back and forth with one another based upon what energy is available.
So the reason I put the qualifier in there at cost is, if they were trading with one another,

they might do a split savings or there may be some profit margin that's built in.

Q. If there was no JDA?

A. If there was no JDA.

And that's what would occur as an island, if the two were an island. So you -- in essence, you save those kinds of profit margin costs that would be built in if the two were trading.

If you've got a wholesale market, then -- that you can buy from or sell into, then -- then the issues of savings and so forth change, because at that point -- let's say you're the company with the cheaper resources that are available. You've met your native load, and you've got cheap, fairly inexpensive resources relative to both the market and to the other company available to sell. And what you would do is sell that to, just frankly, the highest bidder. Okay. So it would either be the market or it would be the other company.

Okay. And there is a profit margin that gets built into that sale, and when you have a JDA, you -- the sale goes to the other utility and there is no profit mar-- essentially no profit margin built in.

The Ameren JDA has a small margin built in for what they call variable O&M and for emission credits. And so the transfer takes place at cost.

Q. Incremental cost?

A. Incremental cost.

Q. So if I understood your testimony, the JDA would allow UE, and has allowed UE to avoid these -- I think you referred to them as profit margin costs?

A. It's allowed both UE and AEG to avoid those. In -- in some hours UE is selling to AEG, so AEG doesn't have to pay these profit margins, or we'll just call them margins, and at other times AEG is transferring energy to UE and UE doesn't have to pay those margins.

Q. And this is an efficiency that results from the JDA?

A. It's a savings that results from the JDA, yeah. I'm not sure I would -- I would have to think about what the word "efficiency" means.

If the market was there and they were buying and selling from the market, I think you would get the same efficiency, but I'm not sure you would get the same distribution of the -- of that efficiency among the players.

Q. If I understand what you're saying, you characterize it as a savings that resulted --

A. Yes.

Q. -- from the JDA and the merger?
A. That's correct.
Q. Did you participate in the review of the UE/CIPS merger?
A. No, I did not. I was -- I reviewed for the Commissioners the filing of the merger before the FERC, and, therefore, did not participate in the state case.
Q. Did you have people working under you in your department who did review the UE/CIPS merger proposal that was before the Missouri Commission?
A. Yes, I believe I did. Mr. Dan Beck submitted testimony.
Q. What about Mr. Tom Lin, L-i-n?
A. Tom worked for a different group at that time. Tom worked for the engineering -- I'm trying to remember the name, but it was the -- it was the -- I believe it was called the Electric Department at that time.
Q. But that was not under you?
A. It was not under me, no.
Q. So you -- you were providing recommendations to the Missouri Commission with regard to the merger proposal that was pending before the FERC; is that correct?

A. I was -- yes, and I was reviewing that.

Q. And because of that, did I understand you to say that you were not involved in reviewing Mr. Beck's --

A. That's correct.

Q. -- testimony?

A. That's correct.

Q. You didn't review it in any shape or form?

A. No, I did not.

Q. Who would have reviewed it then? I mean, who would -- who would Mr. Beck have been answerable to if not to you?

A. Okay. The way that that was structured, and currently is structured, is that there is -- I'm trying to remember back that far. But, typically, there is a case coordinator, and I think there was a case coordinator, and there are also division directors; there are people above me. And there are attorneys. And somebody who is submitting testimony would have submitted it to those three people.

Basically, the division directors -- if the department manager is not reviewing it, the division director, an attorney, the attorney in the case, and who was the third one I said. I forget now. Oh, the case coordinator.

Q. And is that the current practice at the Missouri Commission today where you might advise the Commissioners with respect to a FERC proceeding --

A. Uh-huh.

Q. -- and not be involved in the state proceeding?

A. Yes.

Q. That is current practice?

A. Yes. That hasn't -- really hasn't come up since then, but if it was a merger case, yes. And that's the way we would do that.

Q. Well, was there anything unusual or atypical about the fact that you were representing or advising the Commissioners in the FERC proceeding in the merger case and not involved in the review of the merger at the state level?

A. I'm not sure I understand your question.

Q. Was there anything in your view unusual or atypical about your role in the merger case and being involved only at the FERC level?

A. Only that it was the first time I had ever done that.

Q. Have you done it since in other proceedings?

A. Well, that's what I was trying to recall. I cannot right now bring to mind another proceeding where there was a conflict with something filed at the state and something filed before the FERC.

Q. A "conflict" meaning what?

A. Well, not a conflict. For me -- for a Staff person to be doing one and the other is a conflict. That's what I meant by "conflict."

Frankly, I cannot think of any specific instance in which that has -- has come up or has occurred since that merger case.

Q. Okay. And you were referring -- well, by "conflict," or whatever word you want to use, you were referring to a situation where you didn't think it was appropriate for you to be involved in both the FERC proceeding and the Missouri proceeding?

A. That's correct.

Q. Okay. What was your recommendation to the Missouri Commission with respect to the FERC merger proceeding?

A. I think the Missouri Commission -- I'm trying to recall, but I think the Missouri Commission did not -- was not active -- not real active in the FERC case and didn't in some sense feel like it could -- I mean, I reviewed the documents and that type of thing, but did not make any recommendation.

They could not -- I think they felt like, or the attorneys advised them that they couldn't take a position in the FERC case until they had made a decision in the state case. But there might have been -- there were no issues in the FERC case that I recall that -- that apparently were decisions in the state case.

Q. So would it be correct to say that you -- you don't recall proposing any recommendations with regard to the JDA?

A. That's correct.

Q. Did you provide advice to the Missouri Commission as to the reasonableness of the JDA?

A. No, I did not.

Q. Did you provide any recommendations to them about the JDA at all?

A. No, I did not.

Q. Do you know whether the Missouri Staff proposed any changes to the JDA in the Missouri merger proceeding?

A. I don't recall whether they did or didn't.

Q. Okay. Let me represent to you that the merger began January of '98.

A. Okay.

Q. That's my recollection, January 1st of 1998. Since that time, is it your belief that UE

has received benefits from the JDA?
A. Yes.
Q. And what would you say they have been?
A. I haven't estimated them along the way, but in the recent runs that we've done, they have -- if you compare what their costs would be under a stand-alone versus a joint dispatch, we're showing somewhere in the order of magnitude of $3 to $4 million savings.
Q. Per year?
A. Per year, yeah.
Q. So $3 to $4 million of savings per year since January of 1998. And what are these savings attributable to again?
A. It's a comparison of what it would cost to supply energy on a stand-alone basis, as a UE stand-alone company, to its native load versus what it would cost to supply energy to its customers from the joint dispatch given the Joint Dispatch Agreement.
Q. Okay. Now, if I remember correctly, you said a moment ago that you hadn't -- well, let me start over.
This $3 to $4 million, how would you characterize that? Is that back-of-the-envelope calculation? Is it the result of a detailed study?

A. It's what we're showing currently in our fuel runs that we ran for this case.
Q. For this case?
A. Yes.
Q. And is that reflected in the testimony or the work papers of a Staff witness?
A. Yeah. It would show up in the work papers of Leon Bender.
Q. Okay. And do you know what period Mr. Bender looked at in calculating these savings?
A. He had a test year that was using normalized loads, normalized outage schedules, the -- so this is a normalized estimate of what these differences are.
The test year, as I recall, was the twelve months ending June of -- was it 2001, updated for that summer, updated for July, August, and September.
Q. I'm going to have a series of questions for you later about what "normalized" means, but --
A. Okay.
Q. -- just to focus a bit on the time period, what's your understanding of the time period that Mr. Bender looked at to develop his normalized numbers?
A. It was the -- my understanding is that that time period was determined by the Commission as the

appropriate time period to be used in this complaint case.

Q. Okay. But is it your understanding then that Mr. Bender only confined himself to that period allowed by the Commission to determine his normalized numbers?

A. Yes.

Q. So it's your understanding he did not look outside of the test year to determine his normalized numbers?

A. Well, please explain what you mean by "look outside," because, I mean, any time that you -- any time you run a production cost model, you're -- you're going to look beyond that year. But the run -- the production cost model run that I'm talking about that Mr. Bender ran was for that test period.

Q. Okay. We, let me dive into this topic of normalized.

A. Okay.

Q. Tell me what you mean by "normalized."

A. Oh, gosh. Normalized -- costs occur in cycles, and those cycles may not be from year to year to year. Some costs may occur on an 18-month cycle. For example, the refueling outages at Callaway plant are on an 18-month schedule. Other plant maintenance may be on a two-year cycle, and every five years a major maintenance outage.

So one of the -- one of the issues with normalization is to -- is to try to bring those cycles into a one-year time frame. So things that aren't in a year cycle and you're trying to bring into a year time frame. That's part of the normalization.

Q. Excuse me. That's generally what I was trying to capture when I was saying to look outside the test year.

A. Yes. So you have to go outside the test year to determine what these cycles are. That's correct.

The load, you may have a very abnormal year in terms of weather so that you -- you either have very low load levels, you don't have peaks, or you may have a very high, abnormally high set of loads. So we normalize the loads for weather.

So those are really the two major categories in doing the production cost normalization, is normalizing the loads and normalizing the costs.

Q. Okay. And is that your understanding of what Mr. Bender did?

A. Mr. Bender put inputs into the model that would normalize the costs, yes. He was supplied normalized loads from Ms. Lena Mantle.

Q. Okay. Now does Mr. Bender report to you?

A. No. He reports to Ms. Mantle.

Q. Okay. Who -- and does Ms. Mantle report to you?

A. No. Ms. Mantle also reports to Warren Wood.

Q. Okay. But not --

A. But not to me.

Q. Okay. I think you've answered my question, but let me make sure.

By "normalized," you were discussing what Mr. Bender did as you understand it. And I gather you would use the same definition of "normalized" with respect to what you did for purposes of your testimony?

A. The same concept, yes.

Q. So when we're talking about normalized, it's the same thing -- Mr. Bender did the same kind of analysis that you did --

A. Right.

Q. -- in terms of what periods of time he looked at to determine the cycles that you were referring to?

A. That's correct.

Q. Okay. And did you have discussions with

Mr. Bender or anyone else at the Staff about the normalizing process as Staff viewed it?

A. With respect to what?

Q. Generally with respect to the Staff's March 1st testimony.

A. Well, let me focus on my testimony --

Q. Okay.

A. -- which dealt with primarily the profit margins from off-system sales. And, yes, I discussed the issue of normalization with Greg Meyer.

Q. And can you summarize that discussion for us?

A. Yes. Normally -- well, normally. In the past, when we've run return fuel model, we have -- we have not included in that model off-system sales. We've included off-system purchases and -- and the resources that the utility has, or in this case the two utilities have. And we go back to the books, what was booked for profits for off-system sales for the test year.

Mr. Meyer and I discussed that in terms of what we would be looking at here, and we were -- he -- Mr. Meyer was concerned as to whether the summer of 2000, which is in the test year, was abnormal, and our hope was to update that for the summer of 2001, if it was abnormal.

From what he -- I think from what he had looked at in terms of past records, the summer of 2000 may have been a little high in terms of the profits that were brought in by UE. So we discussed it at that level.

Q. Did you have any discussion about the normalized -- the normalizing process and how Staff would apply that process?

A. To --

Q. To your testimony?

A. To off-system sales?

Q. We'll start with that.

A. Okay. I think -- I think I've given you the only discussion that we had, was we wanted to try to -- to bring in the update period, the summer of 2001.

Q. Okay. You were talking five minutes ago about benefits that you believe UE has received from the JDA since January of '98.

A. Yes.

Q. And we were talking about the -- the savings that are addressed in Mr. Bender's testimony. Correct?

A. I don't know if he addressed the savings in his testimony, but I -- his work papers indicate that level of savings.

Q. Okay. Are there other benefits that UE has received from the JDA since January of '98 other than what Mr. Bender has reflected?

A. None that come to -- readily to mind.

Q. Okay. Well, would you agree that it's a benefit to UE to be able to get energy at cost from AEG under the JDA?

A. Yes.

Q. And that's a benefit because it allows UE to hedge against market prices?

A. In -- the problem I'm having with your statement is when -- with the word "hedge" is when do you need to hedge? If what you're talking about, it allows them not to have to pay that margin to the market, yes.

Q. Well, let me just be direct. I'm referring to the technical memorandum that you authored and that you provided in response to data requests.

A. Uh-huh.

Q. And in that technical memorandum -- do you have it available?

A. Yes.

MR. DOTTHEIM: Mr. Raybuck, can you be more specific as to the memorandum you're referring to, a dated and a case number?

MR. RAYBUCK: Certainly. It's dated December 20, 1999. It's Case No. EA-2000-37.

BY MR. RAYBUCK:

Q. Do you have that available?

A. Yes, I do.

Q. I believe somewhere in your paper -- I don't recall where -- you indicate that one of the benefits to UE was the fact that it could get energy from AEG at incremental cost as opposed to at a market price?

A. Market price. Yes, I agree with that.

Q. And when the market prices are high, this allows -- this ability to get energy at cost allows UE basic-- it's a benefit to UE in that UE can use it as a hedge against market prices?

A. Yeah. Well, the problem is the statement, "when market prices are high," and in the -- and I haven't done an analysis of this, but when market prices are high, it's usually when weather is hot, and almost all of the -- almost all of the generation resources have to be dispatched.

Now, I would agree with the statement if -- if the issue had to do with a lot of reserves that AEG had relative to UE. If both of them were holding generation reserves, those generation reserves provide a cost hedge from having to buy from the market. Okay.

Now, whether UE has a hedge from AEG's resources or AEG has a hedge from UE's resources is a function of what their reserves are -- I think is a function of what their reserves are to some extent.

Q. And that's a dynamic kind of thing --

A. Yes.

Q. -- which changes as conditions change?

A. That's right. That's correct. I think when they first merged, AEG had significant reserves. I don't remember exactly what they were at that time, but I think they were in the close to 30 percent range. And in that context, then, UE -- AEG would be providing UE with a significant hedge against high prices, high market prices.

Q. Okay. Let me return to that topic a little bit later.

Let's talk about other benefits to UE as a result of the JDA.

If there was an outage of a UE plant, or -- well, take Callaway, UE's nuclear plant.

A. Yes.

Q. If there was an outage at Callaway or a refueling at Callaway, the plant would be unavailable for some period of time.

A. That's correct.

Q. And would it be correct that UE would derive benefits under the JDA in that situation where Callaway was unavailable?

A. They could.

Q. Okay.

A. They could also potentially be buying from the market at that time if the market is cheaper then the resources available from AEG.

Q. Okay. Again, that seems to relate to the hedge that maybe we're having difficulty with.

A. It relates to the difference between market price and cost. I agree with that, yes.

Q. Okay. So depending on where market prices are, if there is an outage at a UE plant, the JDA could provide benefits to UE in terms of allowing UE to have access to AEG generation at incremental cost?

A. That's correct. By the way, most of that is reflected in the $3 million, the $3 to $4 million that I discussed, because that goes through a model that probablistically runs outages through it and takes that into account.

Q. And you're talking about Mr. Bender's work?

A. Mr. Bender's work, yes.
Q. And did Mr. Bender's work take into account the effects of the weather and the effects, for example, of a hot summer?
A. No. If you're talking about an abnormally hot summer, no. It was run against a normal weather scenario.
Did it have a peak -- a high peak day in it? Yes.
Q. Let's talk for a minute about a hot summer.
If -- let's assume there is a very hot summer day. Would you agree that the JDA could provide benefits to UE again as a result of UE being able to have access to AEG energy at cost as opposed to going to the market?
A. Well, that's a very -- UE has got three choices if you want to think of it. UE can go to UE resources or it can go to AEG resources or it can go to the market. Okay?
Q. Okay.
A. Now, if on that very hot day a -- and here is kind of my supposition, is on that very hot day, AEG's -- all of AEG's cheap resources have been committed, all of UE's cheap resources have been committed, and what we're talking about are combined

cycle units that each of them may have available. And in that case, it's probably -- you know, you're talking about some marginal benefit is gas might be cheaper at one than it is the other.

But it's the amount of resources that are available to the system that provides, as you've put it, the hedge against the high market price or high price of having to buy it from the market.

Now, if you set up your system so that both companies are balanced in terms of their reserve margins, okay, then you don't get in this situation where you're depending upon the other company to provide you the kind of hedge that you're talking about.

If, on the other hand, you made a decision to build all of your new resources, all of your additional capacity that's needed for growth in one company versus the other, yes, you can get into the type of situation where one company is actually depending upon the other company to -- for the hedge that you're discussing.

Q. Okay. Were you in -- we were talking about your technical memorandum.

A. Yes.

Q. And this was something you wrote in a proceeding where UE asked for Missouri Commission approval to transfer the CIPS generating units to a new affiliate?

A. That's correct.

Q. And that new affiliate was generically at the time called Genco, G-e-n-c-o, for Generating Company?

A. Correct.

Q. And your technical memorandum supported UE's requests?

A. That's correct.

Q. And let me just refer to this for shorthand's sake as the Genco proceeding.

A. Okay.

Q. And do you recall the outcome of this proceeding before the Missouri Commission?

A. The Commission approved.

Q. There was a -- the Commission approved the stipulation among the parties?

A. Yes.

Q. And were you involved in the proceeding at the FERC to obtain FERC approval to transfer the CIPS units to Genco?

A. No.

Q. Okay. You were not involved in any way, shape, or form?

A. No.

Q. Now, Genco ultimately was -- became AEG. Correct?

A. That's correct.

Q. Okay. Now, did -- in -- do you know of any one -- well, do you know what the Commission's involvement was at the FERC level?

A. I don't recall.

Q. Okay. In your technical memorandum on page 4, you list the generating units that Genco was planning to add to the CIPS units once they had been transferred.

A. That's correct.

Q. And those are generally peaking units?

A. That's correct.

Q. And what was your understanding as to the CIPS units? Was it your understanding they were base-load units in nature, or what was your understanding as to those CIPS units?

A. At that time I probably had not -- I had not reviewed or done anything with respect to the units that CIPS had in terms of whether they were base-load or whether they were gas-fired or coal-fired or what they were.

Q. Okay. But somehow you were given information as to Ameren's planned addition of gas-fired generation in addition to those CIPS units?

A. That's correct.

Q. And the units listed in your table 1 on page 4 are in the nature of peaking units. Would you agree with that characterization?

A. Page 4, table 1, yes, they are.

Q. Okay. And did you know why AEG would be adding peaking units as opposed to base-load units or intermediate units?

A. No. Well, I don't recall right now off the top of my head.

Q. Okay.

A. What I recall at this time is that a significant amount of wholesale load was being transferred from UE to AEG -- or to AEM, or that was the plan. And that was releasing -- part of this was the releasing of then some of the UE generation to meet its -- to meet its native load.

Q. And did you support that transfer of the wholesale load from UE to AEM?

A. I'm not sure that I did or didn't. That wasn't the -- that wasn't the issue in this case. The issue was the transfer of the generation assets to the

Genco.
Q. Okay.
A. I don't think that was ever -- that transfer was never an issue before the Commission that I'm aware of.
Q. Of the wholesale load?
A. Right, of the wholesale load.
Q. But that was just an observation that you're making.
A. Right, yes.
Q. Okay. Could you turn to page 7 of your testimony, please?
A. Okay.
Q. At line 6 you talk about transfers of energy under the JDA between UE and AEG at incremental cost. Correct?
A. Correct.
Q. And could you turn to the JDA that we were discussing a minute ago?
Do you -- I can direct you to this if you would like, but do you know offhand where that is reflected in the JDA?
A. It appears that it's on -- in section 6, article 6, Assignment of Costs and Benefits of Coordinated Operations. And under 6.07, it's on

page 9 of the document that I have, is the Assignment of Energy and Costs from System Dispatch.

Q. Okay. Let me direct your attention to Schedule C, Service Schedule C of the JDA at the end of the document -- I'm sorry. Service Schedule B.

A. B, yes.

Q. This is entitled, Distribution -- I'm getting fouled up. Let's try A.

A. A. Okay.

Q. This is entitled, System Energy Transfer, and under Paragraph A3, "Compensation," it says, "Charges for System Energy Transfer shall be the incremental cost..."

A. Yes.

Q. And that -- that is -- would you agree that that's the source of your statement at line 6 on page 7?

A. Yes, the statement that, "All transfers to energy occur at a price that is equal to the incremental cost of fuel, variable operation and maintenance expense, and the opportunity cost of emission allowances"?

Q. Is it your belief that there is something in article 6 which also addresses that or supplements that point?

A. Yeah. Under 6.07, part A) on page 9, this is the -- this is the opposite side of the same coin. It says, the "Energy from the lowest incremental cost generation from each generating party's own generating resources shall first be assigned to its own load requirements."

So if you -- if you've assigned the lowest, then what's remaining -- if you generate more than what's needed to do that, then what's remaining is the highest, and that's what goes to the other party.

Q. Okay. Well, would you agree that Service Schedule A is clear in stating that the system energy transfers are at incremental cost?

A. That's correct.

Q. Okay. Still on page 7 of your testimony at line -- starting at line 9, you indicate that the transfer price does not include the opportunity cost of selling the transferred energy to a third party as an off-system sale?

A. That's correct.

Q. And are you aware of any JDA in effect in the United States which does this?

A. No.

Q. Do you know -- do you have an opinion as to why no other JDA does this?

A. Yes. I think I expressed my opinion on why that's the case.

Q. In your testimony?

A. In my testimony, yeah.

Q. Okay. Now, to -- so you're talking about opportunity costs which you believe should be factored into the price of system energy transfers. Is that what we're talking about?

A. Let me qualify that.

Q. Qualify what? Go ahead.

A. What you just said.

You made the statement that it's my belief that opportunity costs should be factored into the system energy transfers, and I'm not sure that I would say that as a universal principle.

Okay. If I've got two regulated utilities that have come together in a merger context, and depending on what I'm wanting to do with the benefits of those from a policy standpoint, I may not.

Q. You may not what?

A. I may not want the transfers to occur at opportunity costs. I mean, I think it's a policy issue. Here we're talking about transfers between a regulated and a nonregulated entity, so I think there are very specific types of things that should apply.

In essence, the JDA becomes an affiliate transaction and -- or an affiliate type of transaction because you've got the regulated and nonregulated entities, and those -- generally, in that case I would agree that if it's possible that transfers should take place at opportunity costs.

Q. And let me ask you about the assumptions, if any, that you're making with respect to those opportunity costs.

A. Sure.

Q. I gather that you're assuming that there are willing buyers?

A. Yes.

Q. In this case a willing buyer for UE energy?

A. Correct.

Q. And if there are no willing buyers, then the off-system sale by UE would not get made. Correct?

A. There is always a willing buyer at a price.

Now, what you're saying is if UE has $30 energy available to sell and the market price is $25, then there is no willing buyers. I agree. It would not occur.

Q. So if the UE generating unit which would be making this off-system sale had a marginal cost that was higher than the market price --

A. Right.

Q. -- the sale would not get made?

A. That's correct.

Q. And there would be no opportunity cost to factor into the system energy transfer?

A. Yeah. In that particular instance, you would have to ask the question, why isn't AEG buying the energy from the market and not -- and not taking the transfer from UE? If the market is selling at 25, UE's incremental cost is 30, AEG should be buying from the market, not from UE.

So you have to -- you have to get in -- in the context of when these transfers are taking place, what -- what we're trying to reflect is the market as it exists today, and the market as it exists today is, as we have tried to put it and model it, is that there is a market price but there is a limited amount of energy that can be purchased.

Okay. So there is a limit to what you can buy at that price, and that has a lot to do with the imperfections that are in the market today.

So what can happen in that context is that now UE has incremental generation that's above the market price that they are transferring to AEG because AEG cannot buy everything from the market. It's bought up to a certain maximum level.

Q. I think I understand the qualifications you're making, and given those qualifications, going back to the question, if UE's unit that would be making the sale --

A. Yes.

Q. -- has a marginal cost which is above the market price, that sale would not get made?

A. That's correct.

Q. Now, is --

A. Let me just add, as a matter of fact, then there is a benefit to AEG from that and there is a benefit to UE from that. If they are making a sale -- well, they are making the sale at cost, so there is no benefit to them. I take that back. But there is a benefit to AEG that they are able to get that energy from UE.

Q. Now, the system energy transfer applies to -- generally to the transactions between UE and AEG. Correct?

A. Uh-huh.

Q. And do you know whether AEG is an Illinois corporation?

A. I -- I don't know.

Q. Well, is this something that you think the

FERC might have an interest in in terms of policy?

A. I haven't thought about it.

Q. Well, we're talking about transactions involving generating units in Missouri and generating units in Illinois --

A. Uh-huh.

Q. -- correct?

A. Well -- okay. Go ahead.

Q. And that has an interstate character to it. Correct?

A. We're talking about wholesale transactions, yeah.

Q. And the FERC has the job of regulating --

A. That's correct.

Q. -- wholesale transactions in interstate commerce?

A. Yes.

Q. And as a result of all of this, is this something you think the FERC might have an interest in?

A. I'm trying to get a context.

The FERC has approved Ameren's JDA. Yes, they have an interest in it. Is that the question? Or is the question, will the FERC have an interest as to whether transactions are taking place at opportunity costs?

Q. The latter.

A. The latter.

Yeah. FERC has a major interest in it and has issued its market design paper, and -- for the new market design for wholesale power markets. And so, yes, they -- they are very much interested in it.

Q. So they would be very interested in how the system energy transfer was priced?

A. Let's get a context.

If what FERC is proposing is a market design that goes into effect, there is no reason for a JDA. Every generation unit will be bid into that market every hour, and transfers, in essence, will take place at market price. It's --

Q. And is that going to get us to this hourly transparent market?

A. Yes.

Q. That's the end state?

A. That's correct.

Q. And do you have an opinion on when we're, if ever, going to get to this end state?

A. If we'll ever get there.

Right now MISO plans to implement the -- let me call it the first stage of that market in -- on

May 1st of 2003. Okay. Discussions are occurring as to what stage that's going to be. At this point it looks like it will be in the Southwest Power Pool and in the MAP regions will be done first. The MAIN region will be done next, and then the ECAR region will be done last. So they are doing a geographic implementation of it.

So if I had to guess for Ameren, since Ameren is in the MAIN region, I would -- my -- and this is a guesstimate, would be May 2005, May 1st, 2005.

But that's -- you know, that's plans right now.

Q. Okay. In the meantime, because of the interstate character of this system energy transaction, is this something that FERC would be interested in in your view as a matter of policy or rate-making?

A. Well, as an issue, yes, but the question that I've raised in the testimony is since transparent markets don't exist, I don't know what you would do about it. I don't know what you could do about it, and FERC is -- and with FERC's interest in, we would go, Why are we looking at this? We're changing the market structure to where we can get to something, so -- and here we've got something that we can't do anything about or with.

Q. Okay.

A. That's kind of what I was trying to say in my testimony.

Q. You've indicated at line 21 on page 7 that a transparent market for electricity does not exist today, and you've explained that you're referring to the hourly market.

A. That's correct.

Q. Are there any longer term markets which are transparent?

A. Let me ask you to -- when you mean "longer term," you mean longer than an hour?

Q. Anything longer than an hour.

A. Yeah. And "transparent," by that you mean that have readily available pricing?

Q. Yes.

A. Okay.

Q. Transparent to somebody who wants to get that information.

A. What the financial side has been trying to do is to develop a market for peak energy which is a -- the energy sold between specified hours, 7:00 in the morning until 10:00 at night, or whatever it is.

It's defined as a standard product. And the attempt has been to -- to get entities, power marketers, whomever, to trade in these products.

Okay. And the hope is -- and market hubs have been set -- so-called market hubs have been set up at different -- I'm hesitant to use the word "locations" but with different labels on them at different places.

So COB is the California/Oregon border. I suppose that's supposed to describe a physical location in terms -- and this all somehow relates to transmission. Okay. And Palo Verde is another market hub. Cinergy is a market hub. Entergy is a market hub. And these products are available to buy and sell at these hubs. And also hopefully futures products. Futures would be sold in these products.

Now, how are the prices reported at these hubs? My understanding is much like they're reported at the New York Stock Exchange. You get a high and low. You can get concept of what the average is. But they are reported on a voluntary basis in terms of the trades that are being made.

You can get price reports on a daily basis as to what -- where trades are occurring. It is a -- almost -- my understanding is comes close to being a bilateral market, but you -- you can sell into -- I think the hubs provide some -- some services where they match buyers and sellers, or attempt to do that. Bilateral would be where you've actually contacted the seller and you have a specific contract with them.

So, yeah, those kinds of markets are kind of going.

Q. Would it be a fair summary to say that you would acknowledge that there is some degree of transparency in these markets that you've been referring to?

A. There are -- there are prices that you can -- you can discover, yes.

Q. And if you go out on the internet, there are on-line indexes, if you will, or subscription services that will provide this pricing information to you?

A. That's correct.

Q. And for a subscription fee, you can dial into -- you used to be able to dial into Enron on line. Correct?

A. Yeah.

Q. I don't know whether it's still available or not.

A. I think there's several places you can dial in and get reports, price reports, daily price reports for these hubs.

Q. And are you aware of the names of any of these?

A. No.

Q. Internet sites?

A. No, no. I don't -- I don't recall them.

Q. But they are available to someone who pays the subscription fee?

A. Yes.

Q. Have you ever looked at any of these --

A. Yes.

Q. -- sites?

A. Oh, I've looked at the prices. They used to be a part of -- I'm trying to remember. All of the -- give me just a second.

Restructuring Today we get on a daily basis, and it used to have on the back page price reports for the various hubs.

Q. And for what -- for what term would they be reporting on? What would be the duration of the transaction that they would be providing information?

A. I don't recall. I was trying to remember whether it was daily or monthly. The report came out daily, and my recollection, but I may be wrong, is that -- is that they were daily numbers. But I know they also had monthly. And that's -- for other purposes, that's something that we were somewhat interested in at one time.

Q. And would these numbers be the prices quoted today in that edition of **Restructuring Today** for some future delivery?

A. They were an index, price index, and I'm not sure that I know exactly how they put that index together.

Q. And would -- would you agree that that kind of information available in **Restructuring Today** and other hard copy editions, together with the electronic information, would provide some degree of transparency as to markets longer than an hour in duration?

A. Yeah, for those markets. It's providing you some price discovery. It's not -- I'm having trouble with "transparency," because that involves a lot more than just price discovery, but --

You have to -- you have to -- for example, you have to know how -- for transparency you need to know how that price applies to me. Okay. And so, for example, if you were looking at the Cinergy index, you're going to have to see how does that Cinergy index apply to me as a seller or to me as a buyer. And it may or may not. There may be some real problems in getting that particular hub to apply to my specific situation. And that's one of the problems with -- with what I would call transparency.

Q. Okay. Well, what I've been trying to do with the term "transparency" or "transparent" is to follow your definition in your testimony.

A. Okay.

Q. That's what I've been trying to do.

Given that, would any of your answers change?

A. Where is my definition? Help me out.

Q. Page 7, line 22.

A. Yeah. "A market where the price at which electricity sells is determined by an independent market facilitator and that price is published for everyone to see."

The problem here -- and maybe my definition isn't all that clear. The problem here is whether -- when I said "price," I assumed a price that's applicable to me, okay, and I didn't say that explicitly in my definition.

So if you take that component out of it -- and I didn't mean to exclude it from my definition, but if you take that component out of it, you would say, Oh, is this a transparent price over here at

Cinergy? My answer may be yeah, it fits that definition.

There is -- there is a facilitator. There is someone who people are reporting their trades to and their prices to, so he's kind of the facilitator in that context. And then he puts -- he has to keep that individual information confidential, but he publishes some summary of that information in terms of -- in terms of a price or an index or a high or a low, or whatever, yes.

But does that help me -- does it help me resolve the issue that I'm dealing with? And the answer is no.

Q. If it's not applicable to you?

A. If it doesn't apply to me, it's not.

Q. These publications like **Restructuring Today** and Enron on line and the other publication services, would they fall within your definition of an independent market facilitator?

A. I think actually they are -- the independent market facilitators are the people who have set themselves up as the hub and they are simply reporting this to these publications. So if -- if Cinergy sets up a hub or Entergy sets up a hub, they've got people that are committed to gathering that information, keeping that information confidential on an individual basis, but publishing aggregate measures of that.

Q. Would you agree --

A. They would be the facilitators.

Q. Okay. Would you agree that outfits like **Restructuring Today** have an incentive to accurately convey to their subscribers the information that they get from these hubs or from whatever sources?

A. Yes. Any information they convey, they have incentive to do it accurately.

By the way, they no longer provide that information, but they used to.

Q. Okay. Would you turn to page 8 of your testimony, line 13?

You talk about the interim period, and as I understand it, you're talking about before -- before we get to this end state where you have an hourly transparent market --

A. Yes.

Q. -- as you've defined it.

And you state that, "In the interim, for rate-making purposes, the profits from off-system sales allocated to UE by the JDA should be treated differently to reflect the lost opportunity in off-system sales from the JDA requirement to serve the other company's load requirements."

A. That's correct.

Q. That's what your testimony says.

And your phrase, "for rate-making purposes," I'm assuming you're meaning for purposes of this proceeding --

A. That's correct.

Q. -- in which you filed your testimony?

And by the phrase "should be treated differently," are you referring to how the profits should be split between UE and AEG?

A. Yes.

Q. Okay. So because of this issue with regard to the pricing of system energy transfers, it's your recommendation that the allocation of the off-system sales in the JDA should be treated differently than the way the JDA treats them?

A. Correct.

Q. And is this -- at what point -- at what point -- when in time did you come to believe that there should be this different treatment?

A. At the point in time that I realized how the JDA was allocating the profit margins. And the way the JDA reads is that it was allocating the profit margins based upon net output, and I would -- I've been aware of that for several years.

My mistake was that I thought that output was net generation output, and I just discovered this last fall that I was mistaken, that net output is actually load.

Q. Net output is defined in the JDA --

A. That's correct.

Q. -- as load requirements?

A. That's correct. "Net output shall mean each generating party's monthly total of the energy delivered for load requirements," is the precise definition.

Q. I'm sorry. Where were you reading from?

A. Oh, from the JDA. Let me give you -- page 3, article 1.12.

Q. Okay. It basically defines net output as each generating party's load requirements?

A. That's right.

Q. And according to Service Schedule B, the off-system sales margin is distributed based upon relative load requirements?

A. That's -- yeah.

Q. And in the fall of 2001, you came to believe that that -- that that was not equitable? Is that a fair summary?

A. Well, my -- and it was my mistake, but I -- my reading of the JDA had always been that profits from off-system sales were based upon the output from the generation. I thought that's what net output was, of each party.

And it wasn't until this fall that I discovered that that wasn't the case, that it was -- that net output was, in fact, load requirement. And that did not seem like a reasonable way in my mind to distribute profits from off-system sales. That's correct.

Q. Okay.

A. So I'm just -- I'm just trying to -- it wasn't like at that point I thought this was inequitable. It was at this point that I realized that what I thought was equitable and what was being done all along was not the way it was being done, is a better description.

MR. RAYBUCK: Okay. How about a ten-minute break?

(A RECESS WAS TAKEN.)

BY MR. RAYBUCK:

Q. We were talking before the break about the system energy transfers, and we've established that under the current JDA, they are transferred at incremental cost?

A. Incremental cost, yes.

Q. Now, is it your testimony -- is it your testimony that you are recommending that the system energy transfers be priced at a market price?

A. No.

Q. Can you explain that for me?

A. My testimony is that ideally that would be the way to price the transfers, but since there is not a transparent market price available, that cannot be done.

Q. Okay. So if and when we ever get to this end state where we have an hourly transparent market, at that point you would -- it would be your recommendation that the system energy transfers be priced at market?

A. That's correct.

Q. Now, later on in your testimony you make the contention that UE should be buying from AEM at the lower cost or market with regard to wholesale -- electricity at wholesale. Correct? I garbled that.

A. I'm sorry?

Q. Let me try it again.

A. Maybe I'm not ready. Go ahead.

Q. I'm probably not too. I garbled that. Let me say it more clear.

Later on in the capacity reserve section of your testimony, you talk about the AEM/UE contract.

A. Yes.

Q. And it's your recommendation that UE buy, or -- it's your recommendation that UE pay or reflect in retail rates the lower cost or market; is that correct?

A. That's correct.

Q. Now, again, assuming we get to this end state for the hourly transparent market --

A. Yes.

Q. -- would your recommendation be that UE buy the system energy transfers from AEG at market or at the lower cost or market, or do you have a position?

A. The way I envisioned it is that -- is that both entities -- any entity would be buying or selling at market price in the wholesale market. And I really didn't envision transfers as you've described them of energy taking place subsequent to these markets being in place.

In other words, in my view, the type of thing that we're talking about today in terms of JDAs and energy transfers would no longer be relevant. They wouldn't take place.

You could still jointly dispatch, but every generation -- the joint dispatcher would be offering generation of all of its units to the market at a price, and whatever -- whatever was taken by the market, that's what gets dispatched and that's what they receive payments for.

Q. Let me try this again because I'm not sure where we're at.

A. Okay.

Q. Again -- well, today we have no hourly transparent market?

A. That's correct.

Q. So is it your position that it's acceptable for the end -- for the system energy transfers to be priced at incremental cost?

A. Yes.

Q. If and when we get to this end state where we have an hourly transparent market --

A. Yes.

Q. -- with regard to system energy transfers from AEG to UE --

A. Yes.

Q. -- would that be priced -- should that be priced under the JDA at market or at the lower cost or market?

A. Let me -- I don't know if I can answer the question that you're asking, because, in my view, when we get to this end state, as you've described it, there will not be transfers from AEG to UE or from UE to AEG for that matter. There will be trans-- there will be sales to or purchases from the market.

Q. Does that assume, then, that there will be no JDA in existence when we get to this end state?

A. That's very likely, yes.

Q. What if the JDA still is in effect?

A. The JDA that we have today does not fit with the market design that FERC has set out for wholesale markets. They are inconsistent --

Q. Okay.

A. -- in my view.

Q. Well, just make the assumption, if you will, that -- that when we get to the end state --

A. Okay.

Q. -- the JDA is still in effect.

A. Uh-huh. It's going to be tough. I mean, I don't know -- I don't know how you're going to make it work given the end state.

Q. Well, would you agree that at that point -- again, we're at the end state; the JDA is still in effect -- that the JDA could provide benefits in that it could avoid UE incurring transaction costs in -- that they would otherwise incur in going to the market?

A. Let me -- let me try -- no.

Q. Okay.

A. If you want an explanation that's -- okay.

I don't think they will have a choice.

Q. What choice?

A. To not go to the market. The way I read the FERC market design, everyone has to play. It is the only game in town, and it is the game that's defined for transmission.

Q. Okay.

A. That's my reading of it. They will not have a choice, so if they don't have a choice, they can't avoid transaction costs.

Q. Okay. Let me -- doesn't the FERC white paper on standardization, if you will --

A. Yes.

Q. -- envision the possibility of bilateral markets being in existence --

A. Yes.

Q. -- in the end state?

A. Yes.

Q. And for these bilateral markets, wouldn't

parties like UE be incurring transaction costs?
A. Yes.
Q. And, again, assuming you don't have to go to the market --
A. Which -- let me -- which market? The bilateral market?
Q. Assuming you don't have to go to either the bilateral market or the other market --
A. Let's call it the spot market.
Q. -- the spot market --
A. Yes.
Q. -- then there could be benefits to UE in avoiding transaction costs under the JDA?
A. My understanding is UE, as all other utilities under FERC jurisdiction, will have to go to the spot market. That's -- that is the only -- that's the way business is -- wholesale business is going to transact. Bi-- a bilateral market is a -- is a financial deal.
Q. Okay. Would it be -- okay. Could you -- you could characterize the JDA as a bilateral agreement --
A. Yes.
Q. -- could you not?
A. You could, yeah.

Q. Let me move on to another topic related to the JDA with regard to off-system sales.
A. Okay.
Q. And I think, as we've discussed, the JDA allocates the profits from off-system sales to UE and to AEG in proportion to their relative load requirements?
A. That's correct.
Q. And we may have established this. Bear with me if we have.
This comes from a Service Schedule B under the JDA?
A. That's correct.
Q. And -- and in -- it's your contention that this is not a just and reasonable method based on facts that exist today?
A. That's correct.
Q. Now, would it be fair to say that the allocation method was just and reasonable when the JDA was proposed in the merger agreement -- or in the merger proceeding? Excuse me.
A. I don't think so. It is my opinion that allocating profits from off-system sales based on load is not a just and reasonable method, and it isn't now and it wasn't then.

Q. Okay. So your view is that, as of day one, this was not ever a joint -- a just and reasonable method?

A. That's correct.

Q. But is it correct that Staff did not propose in the merger proceeding in any forum any changes to the JDA?

A. That's correct.

Q. Okay. And would you agree that the JDA was found to be just and reasonable by the FERC?

A. That's correct.

Q. And -- and when -- with respect to the Genco proceeding when Ameren proposed to amend the JDA, that amended JDA was submitted to the FERC as well for approval?

A. That's correct.

Q. And is it correct that the Missouri Staff or the Missouri Commission did not propose any changes to the JDA in that Genco proceeding at FERC?

A. We did not propose any changes beyond the amendments that Ameren had submitted as a part of that filing.

Q. Okay. And would it be reasonable to conclude that FERC found the amended JDA to be just and reasonable?

A. That's correct.

Q. Now, in the fall of 2001, when you realized that you had made a mistake as to the definition, did you have any discussions with other members of the Staff with regard to filing a complaint at the FERC?

A. No.

Q. Do you know whether this was an option for the Missouri Commission to pursue?

A. Didn't think of it. I don't know whether -- I don't know whether it's an option or not.

Q. Okay. Your proposed allocation method is based on the concept of resource output?

A. That's correct.

(MR. COFFMAN ENTERED THE DEPOSITION ROOM.)

BY MR. RAYBUCK:

Q. And would you agree that that's not defined in the JDA anywhere?

A. Let me look.

Q. Sure.

A. And I'm -- I'm sorry. I'm looking for -- I do not find in the Definitions section the words "resource output."

Q. Okay. Okay. I gather that, according to your recommendation, you would change Service Schedule B to include in B3 the concept of resource output as a substitute for net output?

A. That's correct.

Q. Now, would you agree that this would have -- if the changes were made as you recommend, would you agree that there would be an impact on AEG?

A. Yes.

Q. And would it be reasonable to go to the FERC to -- well, what -- would -- strike that.

Let's assume the Missouri Commission accepts your recommendations to change the JDA in effect. That's the -- that's the gist of your recommendations, to change the JDA with respect to Service Schedule B and -- for the off-system sales and service -- well, strike that. Let me start over.

The effect of your testimony is to recommend that the JDA be modified in effect with respect to Service Schedule B?

A. Are you asking?

Q. Yes, trying to ask.

A. Okay.

Q. You're proposing a modification to Service Schedule B with respect to B3, the distribution formula?

A. For purposes of -- for purposes of this case, I'm proposing that off-system -- profits from off-system sales be allocated differently than as set out in the JDA.

Q. And that, in effect, would be a modification to the JDA?

A. You're asking me -- I'm not sure whether you're asking me a legal question or just a practical question. From a practical standpoint, yes, it's different from what's in the JDA.

Modifying the JDA may be a legal question of modifying a contractual agreement between two parties and having entities approve that who are supposed to approve it. And I have not proposed that in this case. That's the only thing. I'm not proposing that that happen.

Q. But as -- if I understand you, as a practical matter, you're proposing, in effect, that the words of -- different words be included in Service Schedule B?

A. Yes.

Q. Okay. What about Service Schedule A? You may have answered this question, but are you -- are you recommending as a practical matter that different words be used in A3 with regard to the pricing of the system energy transfer?

A. Let me look real quick. I think the answer to your question is no.

I think A deals with system -- yeah, system energy transfers. I am not proposing in this proceeding that system energy transfers be priced differently than they are.

Q. And that's because we have not gotten to this end state?

A. That's correct.

Q. Let's assume for the moment that the Missouri Commission accepts your recommendation with respect to Service Schedule B, and they -- that the Missouri Commission treats the JDA and its Service Schedule B as you would modify it in a practical sense.

A. Okay.

Q. And let's say that one or two years from now we have another rate case. God forbid. We're all concerned. But let's assume that there is another rate case one or two years from now.

Is it possible in your view that the Staff might recommend further changes to the JDA?

A. Depends upon -- that's a possibility, yes.

Q. And what might -- what might trigger that possibility?

A. What is taking place at the federal level with respect to wholesale power markets, the market design, the new transmission service that the FERC is proposing.

Q. Okay. It's a fair statement, isn't it, that this -- the wholesale market has been in a state of great change over the last ten years and is likely to continue to change significantly for the next ten years?

A. That's correct.

Q. Let me ask you some questions now about the second section of your testimony on capacity reserves.

A. Okay.

Q. Let me ask you some questions to put this AEM/UE contract in context.

I think you'll recall that in the fall of 2000, UE made a filing to the Missouri Commission requesting that it be allowed to transfer its Illinois service territory to CIPS.

A. That's correct.

Q. And did you participate in that proceeding?

A. Yes.

Q. And transferring load to another supplier is one way for a utility to meet its reserve margin requirements. Correct?

A. That's correct.

Q. And that's -- is that what UE was proposing to do?

A. Yes.

Q. And would it be a fair statement that the Missouri Staff was not able to review UE's transfer request quickly enough to satisfy UE's timetable?

A. Yes.

Q. That's a fair statement?

A. That's a fair statement.

Q. And UE's timetable, in turn, was dependent upon AEM's timetable?

A. That's what UE was telling us at the time.

Q. And that's because AEM was not willing to wait for what it thought was too long of a period because in the process it might be foregoing other market opportunities?

A. That's what we were told, yes.

[illegible] market opportunities [illegible] to CIPS [illegible] y?

[illegible]

[illegible] service territory to CIPS

A. To CIPS, that's correct.

Q. -- AEM was going to be supplying to CIPS the power to serve the UE/Illinois service territory?

A. Correct.

Q. And an alternative for AEM was to sell the power to another supplier on the market?

A. To sell to the market, yes.

Q. And what you were told by UE is that AEM was not willing to wait because it was concerned about foregoing these other market opportunities?

A. What -- no. What I was told was that AEM was concerned about waiting. They did not -- it wasn't conveyed to us that they weren't willing to wait. But they were concerned about waiting --

Q. Okay.

A. -- because if they waited, they would be potentially foregoing some opportunities.

Q. Okay. And did you obtain any other information to contradict what you had been told by UE?

A. No.

Contradict what I was told by UE at that time? I guess further down the road --

Q. With respect to AEM's concerns.

A. Further down -- well, I'm not sure it contradicted, but later on, or subsequent to that, at the time that UE withdrew its request for the transfer, we were told at that point AEM did not want to serve the Illinois load, that the profit margin for serving the Illinois load was too low.

And is -- this is recollection, so my recollection of that discussion was that AEM would make about a 3 percent rate of return if they had to serve that load and were not willing to go through with the transfer.

Q. And was this information you were told after UE withdrew its application?

A. At the time that they withdrew, yeah.

Q. Okay.

A. I don't recall whether it was a couple of days before or it was in conjunction with, but it was in conjunction with their withdrawal.

Q. Okay. So UE withdrew its request for the property transfer?

A. That's correct.

Q. And as a result, UE -- well, back up.

Had UE transferred the Illinois service territory, that would have allowed UE to meet its reserve margin requirements for the summer of 2001?

A. Yes.

Q. And when the property transfer request was withdrawn, UE had to come up with another alternative?
A. Correct.
Q. And do you know whether there was sufficient time for UE to build generation between the fall of 2000 when it applied for the property transfer request and the beginning of the summer of 2001?
A. That's not enough time to build new generation.
Q. Okay. And so -- so the other alternative for UE is to -- for UE was to buy the power it needed?
A. That's correct.
Q. And it did so through a request for proposal to suppliers in the market?
A. That's correct.
Q. And this was done as a requirement of the Genco order, is that correct, or do you know -- back up.
Why was the RFP submitted? What's your understanding?
A. The reason it was submitted was because Union Electric needed capacity for that summer. It needed reserve capacity for that summer.
Now, in the transfer there were conditions put in there that required an RFP to be issued.

Q. In the Genco proceeding, you're referring to?

A. In the Genco proceeding, right, the Genco transfer proceeding, yeah.

Q. Okay. Could you refer to your technical memo again which you did in the Genco proceeding?

A. Yes.

Q. If you would turn to page 5, please --

A. Okay.

Q. -- you refer to the RFP requirement from the Genco stipulation; is that correct? Do you see that in the first full paragraph?

A. I'm reading that first full paragraph, yeah. Yes.

Q. At the end of that paragraph, you state, in essence, what is required, and I'm paraphrasing, is that under the Staff's approach, UE can enter into a contract with an affiliate only if the affiliate is determined to be the most cost-effective offer through a competitive bidding process in which all bidders are provided with equal information and bidding opportunities.

A. That's correct.

Q. And how would the RFP ensure that an affiliate was the most cost-effective alternative?

A. Well, the RFP process, if it's conducted fairly, is a process in which all of the bids are compared, and the best bid is taken. I don't know. Cost-effective offer can mean the lowest price, but it may not necessarily mean that.

Q. Okay.

A. It may take into account the reliability of the bidder, how -- how reliable you think that bid is. It may take into account other factors. But, typically, it focuses around the least cost bid.

Q. Okay. If I understand your testimony, assuming it was done fairly, the RFP process would ensure that the alternative or alternatives that UE selected were the most cost-effective?

A. That's correct.

Q. And in terms of what constitutes the RFP process, we're talking about the development of the RFP itself?

A. Correct.

Q. And we're talking about who would get submitted to?

A. That's correct.

Q. And we're talking about the review and the evaluation of the bids from the suppliers?

A. That's correct.

Q. And then we're talking about the final selection of the bids?

A. Yes.

Q. Is there any other component that you would include when we're talking about "the RFP process"?

A. I think that describes the process fairly well.

Q. Okay. And would you agree that it's a process that attempts to take advantage of competitive forces?

A. Yes.

Q. And did you review a draft of the Company's RFP?

A. In this instance?

Q. Yes.

A. Yes.

Q. And did you provide comments to the Company?

A. I believe I did.

Q. Do you recall what your comments were?

A. No, I don't.

Q. Do you recall whether UE accepted your comments?

A. Since I don't recall exactly what they were, I don't know whether they accepted them or not. But, generally, if a company -- if we've reviewed an RFP and we have comments, and if the company doesn't accept those, they come back and we talk about them.

And that -- I do not recall talking with the Company over an issue that was in the RFP that was then sent out.

Q. Does that mean that -- was the Company's RFP, as you reviewed it, inadequate in any way?

A. At the time I reviewed it, I did not consider it to be inadequate, no.

Q. Do you recall giving the Company anything in writing to suggest that the RFP was adequate?

A. I don't recall.

Q. Okay. With regard to the RFP process as we've designed it, did you find any evidence that preferential treatment was given to an Ameren affiliate?

A. No.

Q. Did you find any evidence that an Ameren affiliate was given information that was not provided to other bidders?

A. No.

Q. Did you find -- was it your assumption that equal information -- an equal amount of information was given to all bidders?

A. That was my assumption, yes.

Q. And was there any evidence that you uncovered to suggest otherwise?

A. No.

Q. Okay. Now, in this case UE entered into two contracts to satisfy its needs for the summer of 2001. Do you recall that?

A. Yes.

Q. One was a contract with AEM for 450 megawatts?

A. Correct.

Q. And the second was a contract with AEP for 50 megawatts?

A. That's right.

Q. And AEP stands for American Electric Power?

A. That's correct.

Q. Some subsidiary of AEP.

And AEP would not be an affiliate of Ameren. Correct?

A. That's correct.

Q. And with respect to the AEM/UE contract, assuming that there was no better alternative, would you agree that ratepayers were not harmed as a result of UE entering into this contract with AEM?

A. No.

Q. So even if there was no better alternative, it's your position that ratepayers were harmed?

A. Let me back up and hear your question.

Q. Sure.

A. Did you say assuming there was no better alternative?

Q. Yeah. Let me try again. I'll try to be more clear.

Assuming there was no better alternative to UE than to enter into the contract for 450 megawatts with AEM, would you agree that ratepayers were not harmed as a result of UE entering into this contract with AEM?

A. No.

Q. You would not agree?

A. I would not agree with that.

Q. Okay. Let me understand the ramifications of that.

Even if you assume that there is no better alternative, it's your position that ratepayers were still harmed?

A. That they could be, yes. They still could be harmed.

Q. Could be harmed?

A. Yes.

Q. Do you have any evidence that they have been

harmed?
A. Well, I have two major concerns if that's what you're getting to, and the one concern was in this particular process there were two RFPs issued. There was an initial RFP that we reviewed, and then there was a second RFP that went out. And in the second RFP the bids were limited to must-take energy.
And when you -- and I'm going back to your assumption that was limited to must-take energy, and when you limit -- I did not and I still do not understand -- and this is -- why bids were limited to must-take energy at that point.
Q. At the point of the second RFP that you believe was issued?
A. Yes. Why it was limited to -- when you narrow, you may not get the best alternative that's available. Okay. So that's -- that's the one concern I had with the process.
The second concern has to do with an affiliate who is participating in a JDA who is benefiting from the transfer of energy at cost being allowed to charge a market price for capacity, and that is more -- less -- it's more of an equity issue in my mind than it is anything else.
Q. So the second concern is a product of the

JDA?

A. It -- when taken together with the JDA, I -- I have a major concern. If you as an entity are transferring energy at cost and then when you have to turn around and buy capacity, you're required to buy that at market rather than at cost, there is an equity issue in my mind.

And so in that context, the question of harm, or whatever, is fitting under that concept of equity or balance, whatever you want to call it.

Q. Okay. And that would be the case even if there was no better alternative --

A. That's correct.

Q. -- to UE?

A. If that market price turned out to be higher than cost, that would cause me a problem.

Q. Okay. What is the basis for your belief that there were two RFPs issued?

A. That was when the Company came up and described to us the RFPs and the evaluations, and then sent us the documentation. That's what was in those documents, or it's my recollection of what was in those documents.

Q. Well, another way to characterize this would be to say that there were -- would it be reasonable to characterize this another way whereby you would issue one RFP but have multiple rounds of bidding?

A. Could be, yes. I --

Q. Well, do you know whether a second RFP was formally issued?

A. I probably need your definition of an RFP. And I don't know whether it was a second round, but it had set-out conditions in it, and, to that extent, there was some formality to it. It wasn't just, Please update your bids from your initial RFP. That was not my understanding of what occurred.

I mean, to me, the big difference between the first and the second round, if you want to call them that, or RFP, was, in the second one, it was limited to must-run energy. And that was not my understanding of the first RFP or the initial RFP.

Q. Okay. At the time that you believed that the second RFP was issued, did you express any concerns to the Company about the contents --

A. I wasn't aware of it.

Q. -- of that RFP?

A. I wasn't aware of it. I wasn't aware that it had happened until after the evaluation process.

Q. Do you know whether AEM filed the contract for 450 megawatts with the FERC?

A. Yes, they did.

Q. And do you know why it would have been done, why it would have been filed with the FERC?

A. FERC has rate-making authority over all wholesale transactions.

Q. And did you participate in the case at FERC?

A. I work with the Staff. I think our participation was mainly -- as I recall, was a filing that was made by our Washington attorney. It was a legal issue.

Q. Did you make any recommendations to the Missouri Commission as to the FERC matter?

A. I think most of -- my recollection is most all of the focus was on the -- was on the legal issue of whether AmerenUE was required to do a Section 32(k) filing with the state Commission.

Q. You don't recall making any recommendation to the Missouri Commission about the FERC matter then?

A. That's a legal issue. Okay? I -- are you -- I think the recommendations were made by our attorneys to the Commission regarding their filings that -- was I involved in it --

Q. That's my question.

A. -- or did I maybe write some descriptions of what was taking place or help the attorneys? Yes.

Q. Do you recall what -- what recommendations you made?

A. Golly. I think the fundamental position, as I recall it, was that our attorneys felt that the issue is over an interpretation of the Public Utility Company Holding Act as it was amended in 1992. And the Act required if an EWG made a sale to an affiliate, it was required to file with the state Commission a power supply agreement for that state Commission's approval.

And what I recall is that Ameren's position was this power supply agreement was not being made by the EWG. It was being made by Ameren Energy Marketing, and, therefore, did not come under the -- therefore, the state Commission did not have to approve it.

That's -- that's what I recall. I -- yeah. Was I involved in discussions about that? Yes.

Q. Well, what about the issue of whether AEM should be allowed to charge UE a market rate? With respect to that issue, did you make any recommendations to the Missouri Commission?

A. Boy, not that I recall.

Q. Okay.

A. No.

Q. Do you know what FERC ultimately did with respect to the AEM/UE contract?

A. I think it was approved, yeah.

Q. "Approved" meaning that AEM was allowed to charge UE a market rate?

A. Yes.

Q. And do you know why FERC came to that conclusion?

A. I'm trying -- I did read the FERC order, but I'm -- I think they had -- they essentially have kind of a test that they applied, and the test has to do with the reasonableness of the price compared to some outside measure of market price. And they believe that this contract met that measure.

Q. And as a result of that, FERC found that there was no affiliate abuse?

A. They approved the contract, yeah. I don't know if they -- I don't recall reading the order and saying that -- I mean, if there was -- implicitly, yes, I agree.

Q. You agree that FERC found that there was no affiliate abuse?

A. Implicitly. I don't know if they explicitly stated that. But if they approved it -- they would not have approved it if they found affiliate abuse.

Q. Okay. Do you believe that FERC got it wrong?

A. Yes.

Q. Okay. Well, what evidence do you have that there was no head-to-head competition?

A. I don't think I've stated -- I don't think I believe that, so I don't have any evidence.

Q. You don't have evidence that there was head-to-head --

A. That there wasn't. Your question was, what evidence do you have that there wasn't head-to-head competition. I don't have any evidence.

Q. Let me start over.

Let me represent to you that the FERC had a two-pronged test. Number one, was there -- I think the way the FERC refers to it is head-to-head competition.

A. Uh-huh.

Q. And the second test was, was there any contemporaneous benchmark analysis --

A. Right.

Q. -- as to whether the price in the AEM/UE contract was reflective of the market.

Do you recall those being the two tests that FERC applied?

A. Yes.

Q. In your view was there any evidence to -- that was inconsistent with FERC's findings?

A. Well, I guess in my view I don't think the -- the thing that I had raised about the must-run character of the -- of the energy that was purchased, I'm not sure that the FERC looked at that in any detail.

Okay. So I -- I -- I would say that is -- is one of the things that -- and I'm -- and I don't think the FERC looked at the JDA and how this fit together with the JDA. I don't -- I don't think they looked at that either.

Q. Do you know if there was anything that prevented the Missouri Commission from raising those issues at the FERC?

A. I think there was -- I think there was a concern -- my recollection is that there was a concern about raising those issues at the FERC because this could be an issue that was brought before the Commission here as a state issue, as a rate-making issue here. And so -- so if -- if the Commission would express an opinion on it before the FERC, that might be a conflict. So those issues were not raised with the Commissioners and were not raised at the

FERC.

Basically, to try to explain it, the position that the Staff took with the Commission and that the Commission took before the FERC and the Securities Exchange Commission were to bring the Company in before the state Commission under Section 32(k), have that determination made, and then go to the FERC, or whatever.

That -- it was -- that was the strategy that was -- or that was the -- I don't know if strategy is the right word, but that was the sequence that was envisioned at that time.

So all of the pleadings, both the pleadings with the Securities Exchange Commission and the pleadings with the FERC focused on the Section 32(k) approval by the state.

Now, if you put it in this context, if you're holding out that as a Commission you're going to -- you have the right to review something, then you don't file a -- you don't file a position in a case about the thing that you're wanting to review. Does that --

Q. If you can decide it on your home turf, why go to Washington? Is that what it boiled down to?

A. Well, I mean, that's not the way -- that's