BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket No.
TO STUDY THE ISSUE OF SECURITY : AD05-13-000
CONSTRAINED ECONOMIC DISPATCH :
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Renaissance Esmeralda Resort and Spa
44-400 Indian Wells Lane
Indian Wells, CA 92210

Sunday, November 13, 2005

The above-entitled matter came on for conference, pursuant to notice at 1:02 p.m.

MODERATOR: JOSEPH KELLIHER, FERC
CHAIRMAN

P R O C E E D I N G S

CHAIRMAN KELLIHER: -- to the table and any Commissioners in the room come up to the table. We'll probably have a little bit of migration of Commissioners during the day.

And if we could close the doors, please.

First of all, we have a few Commissioners on the phone. I just want to recognize them. They may not be on right now; they'll probably join us later on.

But Commissioner Hamilton I believe is on the phone from South Carolina Commission. I think we'll be joined by Commissioner Field from Louisiana, Commissioner Gaw from Missouri, and Pandora Epps with the Georgia Commission. So a few people are here electronically.

And I'm going to make a few brief remarks and then turn over to my vice chairman for some cogent remarks as well.

First of all, the Joint Board. This is actually something very new for FERC. Since I joined the Commission two years ago I've been looking for an opportunity for a Joint Board and Congress gave us one last year in the Energy Policy Act. So I'm glad for the opportunity.

And I'm pleased that we're here today. This is really the first Joint Board the Commission has held in a few decades. I think there was one in the '70s about the

Alaska Oil Pipeline. There was one held in 1980 relating to Bonneville Power Administration. So this is a pretty rare and infrequent thing for FERC to do. I think my colleagues, my state colleagues probably have more experience with Joint Boards than FERC does since there are telecom Joint Boards.

And I want to thank NARUC for allowing us to crash their meeting and hold this Joint Board meeting during their conference. And I can't think of a better setting for a FERC Joint Board meeting than a NARUC conference.

I want to thank my colleagues for agreeing to meet here in California. I know some people think this is probably a curious location to have a meeting of the South Joint Board. But we are in Southern California; I'd like to point that out.

(Laughter.)

CHAIRMAN KELLIHER: It is true that California did not secede from the Union in 1861. But if you take the Mason-Dixon line and continue it to the Pacific Ocean we're well under it. So that's probably a good enough reason.

But also it does allow the Commission to act early. The Energy Policy Act is a brand new law; it's three months old basically. And it was important for the Commission to hold the first meeting of the Joint Board before the end of the year. And I thank my colleagues for accommodating that desire to act quickly.

And I do want to just make a point: This is the first Joint Board the Commission has held in a long time. But if this proves to be a productive way to do business we could do more business this way. So I'm hopeful that this is actually going to be a productive way to discuss some issues.

Let me make a few comments on economic dispatch. Economic dispatch has been performed for many years, typically on a system-by-system or utility-by-utility basis. It has been done on a regional basis for many years as well. If you look at the tight power pools in the northeast they have done regional economic dispatch for decades. And we have more recent experience doing a different form of regional dispatch in the organized markets.

But the fact that it's been done in a tight pool shows that regional economic dispatch can be done outside the RTO and ISO structure. And economic dispatch is currently performed in the south. And in fact it's done differently than in the RTO and ISO regions. It's also done differently in different parts of the south. In most of the south economic dispatch is done on a system-by-system basis; in Texas it's done on a regional basis. And SPP is proposing its own form of a regional economic dispatch, something that's pending before the commission

Economic dispatch can certainly benefit consumers both in the form of lower costs and in the form of assured reliability. But I want to make a point that there is a difference between efficient dispatch and economic dispatch. Sometimes people have conflated the two. But there is a difference between the two.

Efficient dispatch places a primacy on heat rate. But it's not the only characteristic that's eight on economic dispatch. Economic dispatch looks at the generation operational characteristics such as ramp rate, it considers environmental considerations, and also considers transmission congestion.

Let me just make a few comments about product, about somewhat of the end game of the regional Joint Board process. And I just want to be clear on a few points, that under the Energy Policy Act of 2005 Joint Boards are charged with -- quote -- "considering issues relevant to economic dispatch and making recommendations to the Commission on those issues."

Now in turn the Commission is directed to report to Congress on the recommendations of the Joint Boards, and including, if any, the consensus recommendations of the Joint Boards.

In short, the commission is required to report to Congress. It is not required to make recommendations to Congress. I think that will become more obvious through our discussions if recommendations emerge naturally during the Joint Board discussions of this Joint Board and the other Joint Boards then perhaps we would make recommendations to Congress. But we'll just have to see how those discussions go.

But I just want to make it clear that I don't approach this meeting with any preconceptions of what any recommendations might be. And I just look forward to hear what presenters have to say and what my fellow Joint Board members have to say.

And just one brief point at the end: that I just want to reaffirm that Commission policy on RTO formation is voluntary RTO formation. I probably think that's worth mentioning because some of these issues do arise with respect to economic dispatch and how might it be done in the future.

So with that I'll end my comments and turn it over to my Vice Chairman, Mr. Callahan.

COMMISSIONER CALLAHAN: Thank you, Mr. Chairman. I'll be brief because you took most of what I said.

That's what happens when you have a breakfast meeting with the Chairman the morning of. But that's his prerogative.

(Laughter.)

VOICE: He had some good comments.

COMMISSION CALLAHAN: I know. I had some good comments.

(Laughter.)

COMMISSIONER CALLAHAN: That's okay. You're Chair. I understand.

I'm just glad to be here.

You know, the only thing I want to say is to echo what the Chairman said. No one has any predetermined outcome or predetermined conclusion about this meeting. I would like to encourage my state colleagues to keep both their ears and their minds open as we go through this process today.

And I would encourage everyone that there are no stupid questions. You know, sometimes I think Commissioners get a little -- they're afraid to ask and probe because they don't want people to know that they're not as smart as everyone thinks they are. But at this meeting I would encourage the Commissioners to be open and be honest. If you have a question, ask it. Because I think this is important. Economic dispatch is something that can help the consumers, can help the companies and is good for the country.

Again let me echo what the Chairman said. We are here to talk about economic dispatch -- not efficient dispatch. And I would ask the presenters and the panelists to keep that in mind. I know there's been a lot of attention on efficient dispatch over the last couple of weeks, especially in D.C. with maybe the promulgation of a Senate bill that might come out. But today we're here under the Act to look at economic dispatch. I hope everyone keeps that in mind as we move forward.

With that, Mr. Chairman, I'd like to turn it over to you and we can get started.

CHAIRMAN KELLIHER: Thank you.

Before I turn it over to Kevin Kolevar I just want to recognize some of the FERC Staff that have worked on this meeting. One is standing up so that's convenient. Bud Early has really been our point person on the Joint Boards and I just want to commend him for all of his work on this.

Sarah McKinley was in the room a minute ago. I think she may have left.

And I also want to recognize Thanh Luong. So he will be the FERC presenter after Kevin. But he's done a lot of work as well on this meeting.

So with that, I will recognize Kevin Kolevar, a former colleague at the Department of Energy who is doing good work at DOE these days.

So Kevin.

MR. KOLEVAR: Thank you, Mr. Chairman.

Joe and I have gone back for several years so it's a pleasure to call you that in a public forum.

I will also keep my remarks very brief, not least because the study that everybody is looking to DOE to release shortly has not been released yet. We have missed our statutory deadline, unfortunately. But we are very close, I can tell you. And without giving away -- in a way, I mean, I wasn't sure walking into this -- this being the first one -- I really don't have a baseline to judge on how these things go. And so I kind of wondered, gosh, is it really a good thing or a bad thing that weren't able to get this thing up and delivered to the Hill. But we want to get it out as soon as possible.

And without kind of speaking to it --

CHAIRMAN KELLIHER: Kevin, I just want to say you'll probably do a lot better than that Yucca Mountain deadline.

MR. KOLEVAR: I think we will.

(Laughter.)

CHAIRMAN KELLIHER: A couple of days is pretty close.

MR. KOLEVAR: Yeah. Or the appliance standards deadlines and a couple of others.

But certainly without giving it away, I will tell you that I expect it very soon -- certainly this coming week.

I will tell you that the report also draws a very specific distinction between efficient dispatch and economic dispatch and speaks to both. And I will tell you that, without having too much flavor along the lines, that I think it holds out high hopes. It speaks kind of optimistically to the value of state boards such as this. It is obviously very cognizant of the authority that the states have in this matter.

And, Joe, I think I share your optimism that I hope this is a very useful tool for the states, for the FERC and the Federal Government in general moving forward on this issue.

Thank you.

CHAIRMAN KELLIHER: Thanks.

And when the DOE report is ready we can make it of record in this meeting. And the meeting will -- we will have a public comment period through December 5th.

Is that correct?

December 5, a public comment period. So the DOE report will be part of the record.

Can I ask you, though, on the survey, I don't know what questions you can actually answer. But one of the things, as I said, we're required to make a report to Congress. We are invited to make recommendations as well but not required to make recommendations.

But in the survey that you've gotten can you identify what kinds of statutory and regulatory changes, if any, have been identified in the survey?

MR. KOLEVAR: There have not been any. And, Joe, that was really a function of the time frame in which we had to work.

We were originally asked, when we knew this was coming over we were asked how long we needed. And the reaction -- and only half-jokingly, was 36 months. But with a three month time frame really all you can do in that kind of time is gather back the comments, kind of broadly lay out the practices across the country, speak to some of the difficulties that some of the commenters have provided and lay that out. You know, you can only do what you can do. And notwithstanding Congress's desire to have some very meaty recommendations, that's just not possible in a 90-day study.

CHAIRMAN KELLIHER: Okay.

COMMISSIONER CALLAHAN: Based on 90 days not being long enough, have you all contemplated any follow-up based on the results you've got from what you have right now?

MR. KOLEVAR: Yes. We anticipate that we will -- I think this is going to be -- I mean I know, Mr. Chairman, I know you know Congress's, the Federal Government's interest in this. So I expect that this is going to be something we're going to be dealing with for a while, and not least because the statutory has requirements for the Department to speak to it on a regular basis.

CHAIRMAN KELLIHER: Do any other Board members have questions they would like to ask, or comments about the DOE survey?

Jimmy.

COMMISSIONER ERVIN: Kevin, just as a matter of clarification, doesn't the statute that required you to conduct the 90-day study require you to revisit it annual?

MR. KOLEVAR: Yes, it does.

COMMISSIONER ERVIN: I mean so there as a statutory matter will be follow-up.

MR. KOLEVAR: That's right.

CHAIRMAN KELLIHER: Okay.

Well, Kevin, you're welcome to -- I know we're tag-teaming you today; you're going to the West. We are happy to have you stay, come back after you do the Western Joint Board, however you want to proceed.

MR. KOLEVAR: Okay. I'll probably look to Bud to tell me where and when you guys meet.

CHAIRMAN KELLIHER: Okay.

MR. KOLEVAR: Thanks.

CHAIRMAN KELLIHER: Well, why don't we turn now to Thanh Luong on the FERC Staff for a presentation on economic dispatch.

MR. LUONG: Good afternoon, Mr. Chairman, Mr. Vice Chairman, and Board members. I would like to thank the Joint Board for the opportunity for me to discuss the basic concepts, the practices and the issues of economic dispatch. My presentation today consists of two parts. The first part is the overview high level of the concept of economic dispatch, the utility industry practice of economic dispatch. The second part is to provide an initial list of issues related to economic dispatch that the Joint Board may consider and address them in the final report.

Starting with the definition of economic dispatch, we adopted the definition of economic dispatch provided in the Energy Policy Act Section 1234. The definition is:

"The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

But this definition reflects a very short time of the current issue of the operating of the daily and the real time only.

If you look at it, most utilities dispatch their own generation unit and their own purchased power in a manner or the same way closing up to meet this definition. And in order to achieve the real time economic dispatch on the real time actually a utility has to do a lot more work on the day ahead to prepare for that.

So in order to prepare for that, to plan for tomorrow's dispatch, the utility will start with the forecast for tomorrow, starting with that, and starting with a list of generation that's available to be dispatched for tomorrow because not every generation will be available. There are a few units that will be out for maintenance scheduling, things like that. And then also recognize the operating limit of the unit, you know, just like the Chairman was talking about, the ramp rate, the minimum run time, the maximum output and the minimum output of the generation.

And this also takes into account the characteristic of the unit, you know, the efficiency, the heat rate curve, the variable operating costs for the fuel, for the variable O&M, and the stop costs. So actually you take a lot into account in order to prepare for the next day.

And they also take into account the purchased power that they have already purchased for tomorrow. And also on top of that they have the reserve requirement for tomorrow. Essentially there's a lot of work going on to do that in order to come up with a commitment for tomorrow.

After that the transmission engineer will look at it, the transmission operator will look at it and will look at it in terms of reliability assessment. They take all the information that is provided, the load forecast for tomorrow, the generation scheduled for tomorrow, with all the information like that. On top of that they will look at the transmission status for tomorrow, you know, including R&D, transmission outage, and they will run a lot of analyses to make sure that the load can be served reliably tomorrow without any violation of the reliability criteria.

And they have to do a lot of contingency analysis studies to do what-if. If any piece of transmission equipment fails, make sure that with situation the loads still have to be served correctly.

So with all the planning like that for the next day, well, the next day comes. One would hope that with everything that, you know, things would not change and everything would be very nicely tomorrow. But actually there's a lot of things could change. The forecast could be different; a unit could fail and trip off; a transmission piece of equipment could fail. So there's a lot of work in the transmission operation to maintain the system in order to do that for the real time operation.

And even though with everything -- with nothing changed, you will look at it. Maybe one utility dispatch will affect the neighboring system because we wait, we're interconnected together with the rest of the system. You know, or vice versa. Somebody's dispatch will affect the system. So it's almost like -- the loop flow will get into the picture for that one.

So the transmission operation really monitors and maintains the frequency and, using the automatic generation control room to do load following. And they also look at varying the monitor very carefully, you know, the operating reserve during the real time. If they fall short they can commit a new unit to make sure that the operating reserve is there, you know, for the operation.

And they also monitor on the flow in the transmission. They keep the transmission flow within reliability limits. They keep the --level within the reliability range. And then, you know, the situation can be slightly different when there's congestion, just like the Chairman talking about this congestion situation in real time.

So they can take corrective action to help out -- to limit it, to mitigate the constraint. They can do it a different way limiting new power flow or curtailing existing power flow or redispatch the unit or shedding load or some of the RTO they would do with the market redispatch of the unit, you know, to make sure that the system is reliable.

So that's the idea about the economic dispatch and the unit commitment on the day ahead. So it takes a lot of work. It's not just efficient dispatch that we're looking at in the short term in the real time only.

Now the second part of the presentation will bring up some issues that related to the economic dispatch that can affect the economic dispatch. The first issue that we see is the footprint of the economic dispatch, you know, the size of the area, how big, how small, and what type of unit are you including in the dispatch or what transmission facility are you considering depending on the footprint.

The generator resources included -- does it include a non-utility generation in the dispatch decision. What type of generation are we talking about? The base load unit, the intermediate or the peaking unit. And for the transmission facility it can be included in the planning for tomorrow or how far do you really look into the system, what level of Kv do you model in your system.

So the bigger the system, you know, it can be affected, the economic dispatch, and, you know, the culmination, the implementation for that.

And for the implementation we see there's a few issues. The one is about the frequency of the dispatch, you know, how it's performed, is it every five minutes or fifteen minutes. The communication of information is very important. You know, in order for the transmission operator to do the dispatch they need a lot of accurate information from the utility's own generation and also from the non-utility generation in order to do the dispatch in real time. Without that information they have to know the ramp rate and the heat rate curve, a lot of information that the transmission operator really needed in real time in order to do that.

And the software, too, is very important for that. If the system is getting too big -- if you look at it, the footprint is so huge and it can be complicated, it makes the modeling much harder. The -- have the single point of failure is increased, you know, if you put everything together in one huge footprint to do that.

And the coordination of dispatch across region is also very important. We feel all the information that is passing back and forth and is, you know, the transmission provider also has to give enough information for the unit to follow the dispatch in real time in order to mitigate the congestion if it happens.

With that in mind we had the initial list of issues that we hoped the Joint Board would consider in looking at and addressing in the final report. What is the current practice of economic dispatch in this region. And what is the scope of the dispatch. What improvement could be considered. What are the potential benefits and costs for those improvements. It may be improvement but it may cost much more than we can spend for that.

And how would those improvements affect our enhanced reliability. And last but not least, are there any institutional impediments to identify improvements.

This concludes my presentation.

CHAIRMAN KELLIHER: Thank you.

Do any of the Joint Board members have any questions of FERC Staff on economic dispatch? And the purpose of this was just to tee-up, provide basic information about economic dispatch to really frame the discussion for the next panel.

But if anyone has questions we can ask them now or we can turn to the stakeholder panel.

COMMISSIONER CALLAHAN: When you referred in your first issues for consideration of the Joint Board on your number one bullet point, your second part is what is the scope of the dispatch. When you refer to scope are you talking about a geographic scope or are you talking about the scope of percentage of load that the companies use to dispatch? What are you referring to when you're talking about scope?

MR. LUONG: We're talking about the footprint of the dispatch.

COMMISSIONER CALLAHAN: The actual geographic footprint.

MR. LUONG: Yes.

COMMISSIONER CALLAHAN: Okay.

So you're talking about the distance between a plant and where it's dispatched to versus -- I mean how are you measuring the dispatch? If Entergy was to buy power from Canada, is that what you're measuring it from Canada all the way down? I mean how are you quantifying your scope?

MR. LUONG: We look at it to see -- I mean for the purchased power you can buy it from there. What we look at is the footprint of the dispatch of your own generation to meet your own load. And you can make it how big or how small; it depends on the situation.

CHAIRMAN KELLIHER: Any other questions?

(No response.)

CHAIRMAN KELLIHER: No? Okay.

Thanh, you're going to stay with us for the rest of this session? Okay. So there might be some questions later.

But let's turn to the stakeholder panel. And we'll start off with Scott Henry, the vice president of energy policy with Duke Power.

MR. SCOTT HENRY: Thank you, Chairman Kelliher. I appreciate the opportunity of addressing this Joint Board.

And I have titled my presentation Economic Dispatch, a PE Perspective. I put it there purposefully because I couldn't decide whether I wanted to put a professional engineer's perspective or a power engineer's perspective. I've had the luxury of being able during my career to perform duties first in system planning, and then ultimately in grid operations a few years later.

And then when I went to operations the operators told me that I was actually in the world of a planner's worst nightmare. And I said what is that, and they said you're having to operate the system that you planned.

(Laughter.)

So I've had the luxury of having that experience in both sides. And I appreciate the opportunity of sharing my experience with this Joint Board.

I am going to focus my comments on a few things. I will really be adding a little bit to what Mr. Luong has said. To a large degree he has covered the basic concepts that I was going to cover in my presentation. He's done a very good job with that. But I will highlight potentially some differences of how Duke Power implements certain provisions that Mr. Luong went over.

First of all, we all need to realize that economic dispatch is in the final analysis dependent upon first the integrated resource planning process. Before you can have generating units to actually dispatch you first have to be able to have a long-term portfolio manager calling for the need for various elements of a generation portfolio to meet the obligation. And the focus of that long-term portfolio management is really focused more on meeting seasonal peaks and meeting the annual energies. It's sort of a broad look, looking over a 20-year period. But when you develop that portfolio, that long-term portfolio you do it with certain strategies in mind of how you're going to operate the system.

So once you get your portfolio, your long-term portfolio in place, you then move to the point where you have a portfolio of diverse generation to meet the needs that you may see coming up over the next day, as Mr. Luong indicated, or for us at Duke, the next week. Our portfolio has a large concentration of pump storage generation. Because of the nature of pump storage it's important for us to look not just at the expected conditions for the next day, but the expected conditions over the next week because we're looking prospectively to determine when it's most effective to pump in order to have generation later from our pump storage facilities, or if it's more important to hold onto our pump storage generation because it may not be attractive to pump later on.

So we're constantly having to balance that need.

We run what we call resource commitment studies at least daily. And at each of those studies we look at the next seven days. And we're looking at hourly loads on our system in order to be able to meet the demand on an hourly basis over that seven-day period.

So resource commitment is the second step in the process before you even get to economic dispatch. Then economic dispatch is, as Mr. Luong has indicated, the real time -- and I sometimes call it the near real time -- dispatch of the generation facilities that you have online. You've made a decision of what generating units you need online using your resource commitment or unit commitment process.

And once you've made that determination then you want to utilize those resources that you have online in the most economic fashion to meet your load obligation. And that's typically done in real time but it can be done on more of an hourly basis right prior to real time in particular that's done in our area through the use of economy purchases. When we feel like that there are purchases that can be made out in the market at a cost less than our generation then our marketers will go out and procure that, typically an hour ahead in order to integrate that into the economic dispatch. As a result of that purchase our generation then would be back down in order to accommodate that purchase and keep the system in balance.

So if I could put it in a nutshell, in long term portfolio management you're looking at what you need to build and what you need to acquire in terms of purchase power or self-build. In resource commitment you're looking at what do I want to start up or what do I want to schedule in order to be able to meet the load. And you're doing that on a daily basis looking out over some period of time. And then, lastly, once you get those units online what do I need to run, how much do I want each of my generating units to be outputting in order to have minimum cost to the consumers in your area.

Now moving to the concept of constraints. This economic dispatch is done subject to a number of constraints. And I've not tried t list them all but I've listed some that are indicative: ramp rates, minimum run times, unit startup times, emission limits, planned maintenance schedules because typically if you're looking at the next day you know what planned maintenance you're going to have. And I have listed hydro and pumps storage reservoir limitations.

In addition to our pump storage we have a large amount of conventional run of river hydro which has minimum constraints, minimum release constraints and things like that. So it's a constant balancing act in order to make sure that we meet all of our statutory obligations with permits, with serving our customers, with providing transmission service, because as all these things get integrated together in the dispatch process we're obligated to meet all those expectations.

That leads me to what is a security constrained economic dispatch. Well, simply put it's an economic dispatch that is modified to ensure that the transmission system can accommodate the generation that is being placed on the system. So your economic dispatch routine will produce a portfolio generation output from the various units, and then the security constrained component ensures that the transmission system will not be overburdened in any area by that complement or by that allocation of generation resources on the system.

And then lastly, I think one point I would like to make about third-party resources, as I alluded to earlier, those resources are continuously evaluated to be included in our resource commitment and dispatch processes.

Our bulk power marketing function is charged with the responsibility of purchasing when those purchases can be made at a lower cost than what it would cost us to self-generate. They have incentives that would indicate that that is just as important to the company as utilizing temporarily available surplus to get profits. So within our company we see -- we put the two on equal footing with those people who are actually implementing that transaction and they're out there constantly looking for deals that would help lower the cost to our consumers, in particular our retail and wholesale consumers.

Duke's performance of this activity is certainly subject to the regulatory oversight of our state Commissions through our fuel clause proceedings. We are allowed to recover a component -- or recover the fuel component of these purchases in our fuel clause proceedings and we are certainly subject to prudency reviews and we are audited in our performance of that.

So in summary, I think I would offer a couple of conclusions. From Duke's perspective the current unit commitment and dispatch processes are working. And they are benefiting ratepayers in our area. And we have a robust bilateral wholesale market that is reflected in Duke's commitment process and the dispatch process to the extent that those resources elect to be included.

Now what do I mean by that? Duke's generation is -- Duke's generation resources have connected to them what's called automatic generation control, which Mr. Luong indicated. And for a generating unit to be able to supply what one might call regulation, instantaneous regulation service, typically you have to have that capability in the generating unit. And at this point none of our wholesale generators have indicated an interest in providing that, and in fact it probably is not effective for them to provide it because they're combustion turbine resources.

So we have tried to include to the greatest extent possible -- and I think we are -- third party resources in our dispatching commitment processes, certainly to the extent that they seem to have desired to be included.

Thank you very much for the opportunity to offer these comments. And I'll look forward to any questions that you have.

CHAIRMAN KELLIHER: Thank you, Mr. Henry.

I thought we'd go through the whole panel and then have questions for the whole panel at the end.

MR. SCOTT HENRY: I like that idea.

(Laughter.)

CHAIRMAN KELLIHER: Why don't we go to Mr. Hurstell, vice president of energy management with Entergy Corporation.

MR. HURSTELL: Thank you, Mr. Chairman. I appreciate the Board giving me an opportunity to address a topic so important to our customers as economic dispatch.

Let me at the outset say that Intergy believes security constrained economic dispatch is working. And I could just hand the mic over to Mr. Priest because Intergy does it pretty much the same way that Duke does. But I thought I'd go into a little more information about how we work to expand the effectiveness of it.

And I'm glad Commissioner Callahan mentioned scope because Intergy does make a real effort to include generators outside of our footprint into our economic dispatch. And we have done we believe an effective job of incorporating those market opportunities into dispatch.

If you will turn to page two of the slides you will see two energy mixes, one for 2001 and 2005. And you'll see that during that time frame Intergy has expanded its use of market purchases from 14 percent in 2001 to over 30 percent in 2005. And this is year to date in 2005. While our older gas fired generation in 2001 accounted for 25 percent of our energy mix, in the year to date 2005 it's only down to 15 percent.

So while -- We have done two things: We have broadened our use of market purchases -- and this includes IPPs and other utilities. We have also -- We have used those purchase opportunities to decrease our reliance on our older gas-fired generation.

Now you'll see that in 2005 we wanted to separate the newer gas fired generation that we now own or have purchase contracts for.

And, Commissioner Callahan, you'll recognize that's Perryville and Itala.

So now the issue becomes is the 15 percent. That is what merchant generators have the ability to -- additional generation that they can displace. So now the question becomes can they displace that 15 percent. And the answer would be yes, they could. But if they are -- if you'll turn to slide three -- then they would have to offer products that match the role that our gas fired generation play, and that is load following product rather than a block product.

If you look on the left-hand side of the page you'll see just a graph of our weekly loads. And this is just hourly loads. It ignores the changes within the hour, that can be substantial -- well over 1000 megawatts -- and just looks at the hourly loads.

And on the right side, the upper graph, this is a typical gas fired generator on Entergy's system, one of our older gas fired generators. And you'll see how it operates. We keep it as close to minimum as we can and then we turn it up as we need to to match load or to match some type of imbalance.

Now on the bottom right hand side of the page, these are the types of offers we receive from merchant generators: block power -- block offers. The same amount of power for a defined block for a defined period of time. And you just can't use those block purchases to offset the flexible generation that you see on the graph on the top right-hand side of the page.

Now -- and even if they did offer that type of service we have heard in many studies that the heat rate offered -- that generators can typically offer merchants is a 7500 heat rate. And I'm here to tell you that Entergy has not received many, if any, offers for a 7500 heat rate product from merchant generators.

If you look on slide five, this is information regarding our weekly market. Entergy back in 2002 on its own initiated a weekly RFP to allow generators to better compete with our existing fleet of generators by allowing them to lock in a sale for a week instead of doing it day by day. And what we ask them to do is to bid a heat rate. We don't expect them to carry the gas risk as to what price gas is going to be next week. So they bid heat rate. So it provides us a great store of information regarding what their bidding practices are in terms of heat rate.

And if you look on the left, the claimed heat rate that we frequently hear quoted is a 7500 heat rate.

The average during this period is over 9000. And these are -- the graph on the right, these are the actual bids that we received in this -- the average of the actual bids we received. As you can see, 7500 is just not something that we routinely see in our weekly market.

Commissioner Callahan, I know you mentioned that you didn't want to talk too much about efficient dispatch. But I just want to make one point. And on page five we can illustrate it.

At least for Entergy we have many different gas supply options. And because of that using heat rates to dispatch resources instead of energy cost is not economic dispatch. Location and fuel costs matter.

Just looking at the month of October, the two most heavily traded gas indices in our region are the Houston Ship Channel and Henry Hub. During the month of October there was more than a three-dollar spread between those two gas indices. So you could take an IPP that buys gas from Houston Ship Channel and an IPP that buys gas from Henry Hub. If their heat rates are identical the Houston Ship Channel generator is going to be cheaper. The Houston Ship Channel generator could be less efficient and their delivered cost is going to be lower.

Because a lot of our generation also has duel fuel capability then they can burn oil, like General

Anderson and Baxter Wilson, then they can pay -- they can have a higher heat rate but the lower fuel costs makes them more economic without regard to efficiency.

So I just want to close by kind of hitting our big points in that we believe economic dispatch is already in place and it's working. The merchant generation has been integrated into the current economic dispatch with the same caveat that Scott made is to the extent that they want to be. To the extent that they give us offer we include them. And we include them however they want to be included. If it's daily, it's daily. If it's weekly we include them weekly, or monthly. And we also have annual RFPs that they can participate in.

I won't mention efficient dispatch again.

But the last point is that if merchant generation is going to displace the existing gas fired generation they're going to have to offer the products and services that those generators provide if they are going to displace them.

Thank you.

CHAIRMAN KELLIHER: Thank you.

We will now ask Robert Priest, the general manager of Clarksdale Public Utilities for his views.

MR. PRIEST: Good afternoon, Chairman Kelliher, Vice Chairman Callahan, other Board members. My name is Bob

Priest and I am the general manager of Clarksdale Public Utilities of the City of Clarksdale, Mississippi.

I am here today on behalf of Mississippi Delta Energy Agency, the Clarksdale Public Utilities Commission and the Public Service Commission of the City of Yazoo City, Mississippi.

I'll refer to the entities that I represent as the MDEA Cities. MDEA is a joint action agency of which Clarksdale and Yazoo City are the current members. Clarksdale and Yazoo City own and operate municipal electric systems embedded within Entergy's service area and are network customers of Entergy pursuant to its oat.

MDEA Cities are dependent upon the energy transmission system both for buying power and energy resources, and for selling any power and energy from our resources that are in excess of our customers needs. The maximum peak load of the MDEA Cities is approximately 80 megawatts and the average load is approximately 40 megawatts.

Prior to my current position as general manager of the Clarksdale system I was general manager of the Yazoo City system for a number of years, although I have had approximately 23 years of experience with operating municipal electric systems within the Entergy area.

At the current time there is no coordinated economic dispatch that covers all loads within the Entergy control area and the resources available to serve those loads. Entergy dispatches its resources to serve its own retail and wholesale power customers while other LSEs dispatch available resources to serve the needs of their customers.

Although Clarksdale and Yazoo City are members of the Southwest Power Pool, because we are embedded within the Entergy transmission system we are not able to participate in SPPs imbalance energy market.

Cleco Power LLC provides dispatch services for MDEA under an energy management and service agreement. Cleco utilizes proprietary models to develop load forecasts for MDEA. Cleco then uses a stacking model to optimize the daily production cost and formulate recommendations concerning economic dispatch of our generation assets or purchases of power from the market, subject to transmission availability.

Through its weekly procurement program Entergy incorporates resources from some independent sellers into its dispatch to serve the needs of its own customers. For the reasons I will describe, however, the WPP program discriminates against network customers such as MDEA Cities and independent sellers that Entergy does not select through the WPP.

I note that Entergy has proposed certain modifications to WPP as part of its independent coordinated transmission proposal in Docket Number ER05-1065. Because this is a pending proceeding I will not address the substance of the ICT proposal except to say that it does not fully resolve our concerns with the WPP.

Even before the damage caused by recent hurricanes the Entergy transmission system has not been adequate to allow flexible and efficient use of resources available to the area. For example, economic substitutes for our network resources have been curtailed and transmission service for economic substitutes have been denied due to ongoing problems with the McAdams-Lakeover flowgate.

Based on concerns raised by numerous independent generators in a number of Commission proceedings in which we have participated there are many constraints in the Entergy area which interfere with desired transactions.

Although Entergy's -- WPP allows it to take advantage of independent resources of its choosing, the process discriminates against network customers and independent sellers that Entergy does not select through the WPP. After Entergy receives bids through the WPP it performs an optimization analysis to determine which resources it will select to displace its own resources.

The optimization analysis currently is performed only for Entergy. At times Entergy closes down the available flowgate capacity determination process for others, transmission customers, while the optimization analysis is being performed for Entergy. We understand that such blackouts on AFC calculations for other transmission users lasts for about half a day, during which Entergy's substitute process has an absolute priority.

Other transmission users seeking to use substitute resources cannot have reservation requests processed during the blackout period and are able to use only AFC that is left after Entergy completes its selection. Thus, while the WPP allows Entergy to reap some of the potential benefits of economic dispatch, it does not allow network customers or independent sellers that it does not select in the WPP to do so on a comparable basis.

To promote the efficient use of economic dispatch for the benefit of all loads within the Entergy control area at least two changes to business as usual are necessary. First, the Entergy transmission infrastructure should not only be repaired but it should also be strengthened.

We and other users of the Entergy transmission system have offered to help fund infrastructure rebuilding and improvement in return for an ownership interest in portions of the transmission system and credits against transmission charges. Although Entergy has expressed a willingness to consider that offer further in response to others, it has not responded directly to Clarksdale or made any commitment to take advantage of the offer.

Second, the Commission must ensure that other transmission users -- particularly other network customers -- have access to the Entergy transmission system on terms that truly are comparable to those enjoyed by Entergy. Network customers should be able to obtain transmission service or economic substitutes for network resources on the same basis and the same timeline as Entergy obtains transmission for substitute resources. Enforcing comparable access is especially critical in instances such as presented by Entergy's system where the transmission infrastructure is inadequate.

Thank you for this opportunity to present our concerns to the Board.

CHAIRMAN KELLIHER: Thank you, Mr. Priest.

I would now like to turn to David Beam, senior vice president of power supply, North Carolina Electric Membership Corporation.

Thank you.

MR. BEAM: Thank you, Chairman Kelliher. I'd like to thank you and Vice Chairman Callahan and the other members of this Board for the opportunity to speak today.

I believe you'll find that NCEMC has a unique perspective on the issue of economic dispatch which we hope you will seriously consider as you develop recommendations based on these proceedings.

Economic dispatch in the area of the southeast in which we are located is typically performed by vertically integrated utilities operating control areas, or in the more modern parlance, balancing authorities. Other members of this panel have explained quite convincingly that they do a very effective job of extracting maximum economic value out of the generation under their control while at the same time ensuring reliability of the system.

I would not dispute that they do a very effective job within the scope of the generation and transmission system within their control. However there are entities such as NCEMC which are not part of this economic dispatch which fact significant impediments which make it difficult to efficiently utilize our own resources, much less take advantage of efficiencies in a broader wholesale market.

First a little background on NCEMC. We are one of the largest G&T cooperatives in the country with load obligations exceeding 3200 megawatts. As a load serving entity we have the same native load obligation as our investor-owned neighbors. We are also a transmission dependent utility, meaning we are completely dependent on the transmission access promulgated in Order 888 to deliver economic and reliable power supply to our customers.

Our load is also spread over three different transmission providers, meaning we have to move our power supply resources across three different transmission interfaces incurring separate transmission wheels and losses.

Finally, the majority of our power supply comes from long-term bilateral contracts which must be scheduled rather than generators under automatic generation control.

It's easy to think that this industry consists of traditional utilities and merchant generators. But it's important to realize that there are many entities that do not fit the mold of either.

Why do these factors make us different? A balancing authority operates in real time, meaning that they can react instantly to changes in load and market conditions. We are not included in a balancing authority dispatch. Instead we rely on schedules between multiple control areas to serve our load. The rules for scheduling of resources provide limited flexibility to adjust our resources to optimize economic benefit.

Most scheduling today is done on a day ahead basis with very limited inter-day scheduling flexibility. Therefore we must set our resource mix a day in advance based on projections of loads and market conditions. Without the ability to adjust our resources in real time we are never going to be operating in a truly optimal fashion.

A further complication is load balancing. We are required to schedule in discrete blocks instead of being able to adjust out further in real time. The result is that our resources will never match our load exactly, resulting in very costly energy imbalance penalties. While we've had some success in dynamic scheduling, this process is complicated and expensive.

The southeast has a very liquid market for economic transactions. There is no central clearinghouse for matching up buyers and sellers. Utilities typically engage in bilateral transactions and day ahead block schedules, relying on phone calls to potential trading partners to identify economic opportunities. Obviously this is an inefficient system for optimizing resources at the lowest cost.

Perhaps the biggest impediment to economic dispatch is constraints on the transmission system. We frequently find we are unable to access economic sources of energy because of transmission limitations. In addition we often forego economic transactions because of concern that the transaction could be curtailed because of lack of transmission.

NCEMC believes that regional planning and operation of the electric system beyond traditional control area boundaries is necessary to resolve many of these problems. At the same time we are cognizant of the concerns expressed by many utilities and state commissions on moving towards RTO based markets.

We have experience in PJM and understand some of the implications of those markets. PJM has resolved some of the concerns that I have expressed here today, but we've also found other problems with operating in a PJM type market.

So we believe that solutions can be found which extract greater efficiency without mandating an RTO structure. As an example, load-serving entities in North Carolina in cooperation with the North Carolina Utilities Commission recently established the transmission planning collaborative process to jointly plan the transmission system for network customers.

We believe that this Board should look for innovative ways such as this to improve the economic operation of the electric system without mandating a single prescriptive solution.

I thank you again for the opportunity to speak with you.

CHAIRMAN KELLIHER: I want to thank you, Mr.

Beam.

We will now turn to Sam Henry, the president and CEO of SUEZ Energy Marketing North America.

MR. SAM HENRY: Thank you, Mr. Chairman. Thank you also to the Board for the opportunity to let me come here today and share some observations and thoughts about economic dispatch.

First I thought for those of you who may not be familiar with SUEZ, I'd give you a brief snapshot about our company. The company got its name because it was one of the financiers of the Suez Canal. It's been around for about 150 years. It's a large company now; it has about 160,000 employees around the world and operates in more than 100 countries.

Here in the U.S. we have three principal lines of business. The first is the LNG business. We own a terminal in Boston and are one of the largest importers of LNG into the U.S. Our second business is retail sales of electric power. We focus those sales on commercial and industrial customers and operate currently in 11 states in the U.S.

And our third business is electric power generation. We have two sets of business there. One is there merchant power business and the other is the business that sells fully contracted power over long periods of time.

My group, SUEZ Energy Marketing, actually manages the fuel procurement commitment dispatch operations for those merchant plants.

In the south we have a position of about 1100 megawatts in ERCOT, 750 megawatts in Arkansas, about 1000 megawatts in Mississippi. In other parts of the U.S. we have 500 megawatts in the state of Washington and about 30 small plants located mostly in the U.S. Northeast.

I thought I would spend a few moments today just highlighting three regulatory initiatives that are of particular interest to us and impact our generation plants. The first is the transition to nodal pricing that's occurring in ERCOT. The second is the Louisiana Retirement Study that's underway. And the third is the initiative regarding the independent coordinator of transmission.

First with regard to ERCOT we very much support that activity. As you know it's been going on for about two years. And the benefit is that nodal pricing particularly in ERCOT provides greater price discovery, transparency, and sends the right price signals to the market.

A study conducted for ERCOT found that more than one billion dollars in savings would be achieved over the next few years for consumers by the switch to nodal pricing.

With regard to the Louisiana Retirement Study, I want to applaud the efforts of Commissioner Jimmy Fields and the Louisiana Public Service Commission at their November 9

LPSC meeting where they asked for an update to the retirement study. The original retirement study was done assuming four dollar gas and assuming 5000 megawatts of generation were required into the Entergy system. And, as you know the gas price has a significant impact on economic dispatch.

The price of natural gas for 2006 in the forward market currently averages above $10.50. So the four dollars was clearly out of the market.

I think the benefit of the new updated retirement study will of course look at the impacts of gas on the retirement of those old units and will target a date for an RFP to allow the market to compete.

With regard to the independent coordinator of transmission initiative, we think this creates a needed transparency of the allocation of transmission. Currently when those allocations have taken place it's not publicly visible so that market participants such as ours can understand how the transmission was allocated, why it's available and why it's not. The study also will facilitate integration through the system and really focus on efficient generation.

We also support the concept along with participation of the stakeholder process. When you look at it one step away, though, what we really need is the integration of these studies. The retirement study will lead toward improved fuel efficiencies because the newer plants tend to use less natural gas to produce the same amount of power than the older ones. The ICT can optimize transmission allocation, and we need the -- economic dispatch really will integrate two of those concepts: How do we make the dispatch of generation more efficient; how do you allocate transmission in a more efficient way. So together those will lead to economic dispatch.

Why do we need economic dispatch? One, it provides needed transparency in the market. It removes the inherent conflict that exists within a vertically integrated independently owned utility. There are potential fuel savings, and at high gas prices those savings have really been -- the potential savings are amplified.

It also identifies the price of congestion and highlights possible transmission upgrades.

The electric market is dynamic and we need a mechanism that provides a quick response from all market participants.

In a recent LSU study it showed that there would be more than $900 million in fuel savings achieved if we had economic dispatch. Our own SUEZ studies have shown that fuel savings could be as much as $500 million per year. Now that study was conducted using six dollar gas prices and also did not consider security constraints. But all in all, it's still a huge number and I think it needs -- there is the opportunity to save more money by going toward economic dispatch.

Economic dispatch, of course, takes into account the entire system, transmission and generation, to properly allocated resources. Our suggested system goals from economic dispatch would be to make a more transparent allocation of transmission capacity, to make a transparent algorithm on how to evaluate resources. It would consider the system limitations and it would be granular enough to provide investment price signals.

The system attributes we believe that would be present in an economic dispatch system would be a day ahead market rather than real time where offers and bids are matched on a day ahead basis and settled in real time. The bids would be three parts: they would consist of start costs for each unit; there would be no-load costs, and there would be bid curves from which the economic decisions could be made.

The system would be dispatched every 15 minutes to ensure efficiencies and there would be LMP pricing, the locational marginal pricing. That provides the needed price granularity and sends critical price signals to the market.

In conclusion we believe that economic dispatch should respect regional and state differences. Any federal mandate can only be the empowering mechanism for state jurisdictions, not the architect of a specific regional plan.

State commissions are the appropriate jurisdictions for the implementation of specific economic dispatch protocols. There should be a significant stakeholder process like existed in ERCOT so that the input of market participants could be taken into consideration. And the overall impact of economic dispatch should consider the cost effectiveness solution given the operating limits, market conditions and needed cost recover.

Thank you very much, Mr. Chairman.

CHAIRMAN KELLIHER: Thank you, Mr. Henry.

I would now like to turn to Robert O'Connell, the manager, regional government affairs of Williams Companies.

MR. O'CONNELL: Good afternoon, Mr. Chairman. Thank you.

Mr. Chairman, I'd like to thank you, I'd like to thank Vice Chairman Callahan and the other state commissioners that are here to listen to us talk about economic dispatch.

And I'd also like to commend your staffs that helped us put this together. There was a lot of hard work that went into making sure each of us knew where to be, when to be and what all we needed to bring with us. And without that hard work it would be difficult for us to come here and intelligently discuss these issues with you.

Williams Power Company is a full-requirements load serving entity in the south. Williams is in the middle of a long-term power supply deal with four of the electric membership corporations in Georgia. We serve approximately 600 megawatts of load today and we forecast that load to be as much as 1500 megawatts before the agreement expires in 2015.

In support of a transaction like this we go out and sign up different supply arrangements. One of our supply arrangements is a long-term tolling contract.

And by tolling contract I mean we're going out with a generation owner and we're giving the generation owner the risks and responsibilities associated with operating a plant, and we're taking on the risks associated with fuel, market price, and things of that nature, so that we're in essence marrying our core competencies together to make sure that we have a full suite of competencies to best take that plant to market and work that plant as hard as it can in the market.

That plant is the Lindsey Hill Plant. It's in central Alabama. And it's connected to the Southern Transmission System.

We have another long-term agreement with Cleco for the Evangeline Plant, which is in Louisiana. It's the same type of deal, tolling deal, where Cleco takes on the operational risks and we take on the marketing risks.

Our interests in this area are aligned with our customers' and aligned with the retail customers in the region. To the extent that we can lower costs to our customers they can pass on those savings to the retail customers in the region.

We're interested in economic dispatch because we want the lowest practical cost consistent with prudent levels of reliability and with the least disturbance to the environment. We think operating in that fashion in this region brings all the interests together and looks out for the interests of the retail customers who eventually receive the products that we deliver.

In support of our load serving deal in Georgia we go through the same process that the integrated utilities go through in planning for each day. We develop load forecasts; we survey the status of resources.

And by the status of resources, we're interested in what their availability is; we're interested in what their problems are. We want to know if a particular resource is maybe hampered by a particular operational problem that may wind up being an outage at some point during the day. Knowing something like that may change our decision of how to deploy that resource.

After we get through that we develop a resource plan that includes some system purchases from bilateral transactions. It includes some of the resources that we have access to through our own portfolio or through the portfolio of our customers. We then schedule those resources and schedule the necessary transmission service to bring all those resources to the table during the operating day.

We also continually review this plan. As things change, load forecasts change, as weather changes, as fuel availability changes and things like that, we need to make sure we go out and make the proper changes to our plan so that we're bringing the proper level of reliability and the least cost we can to our customers.

We revise those plans as necessary to reflect changes that develop.

One of the significant difficulties we have in performing this function in the south is that there is a lack of transparency and efficiency in the congestion management activities. Utilities in the region use internal transmission loading relief -- or TLR -- processes to manage transmission availability during the operating day. Because these are internal and not NERC transmission loading relief activities these events -- or the activities under these procedures do not get published. The procedures are not published; the business rules are not published. And in essence we're trying to drive down the highway with the hood over our heads.

That hampers us. It hampers us in developing prudent plans that give adequate consideration to reliability. If we know there's a pending transmission problem or there's been a certain transmission problem that's been popping up on similar days we may decide to make sure that we have sufficient fuel delivered to maybe an oil plant so that we can operate that oil plant in lieu of something else.

But unless we have the information that tells us what the reliability landscape looks like, it's difficult for us to really go through and develop a robust plan that looks after all the considerations we need to in looking after our customers' interests.

The lack of visibility into these transmission-loading events also hampers our ability to respond. We're not quite sure why there were transactions curtailed; sometimes they don't involve our particular transactions but you hear about them via word of mouth with others in the industry. We're not certain if we make a certain adjustment if that's going to help or hinder the particular problem that the utility is seeing.

So the lack of transparent and efficient congestion management in the region is a real obstacle and a real barrier for us to plan and operate the portion of the system we need to.

Another thing that hampers us is the lack of organized markets to address balancing. Oftentimes we're in a situation where we're operating a power plant at partial load in a manner that's very inefficient, but we need to do so to meet our own resources, yet we don't have an avenue to get out and bring that to market. So that organized markets to address balancing will help us further in our abilities to achieve this economy for our customers.

Other disconnects in the region. We have some difficulties from time to time between gas markets and electric markets. Electric markets operate 24 hours a day, seven days a week. Gas markets operate on business days. Gas markets operate on what they call the gas day, so that for example on a Friday morning they trade gas for the period that starts some time mid-morning on Saturday through mid-morning on Tuesday. Well, sometimes there's something that happens -- loss of a major plant, loss of a major transmission line -- that happens on a Sunday afternoon or evening and now all of a sudden we have to go out and hunt for gas.

Because of the lack of organized markets and liquidity in those markets really what you're looking for is somebody that has a huge position that they can transact with you based on that position. Sometimes trying to find that is very difficult. And we can't optimize our dispatch because this emerging need for fuel cannot be met. It tends to be less of a problem with oil plants because you tend to be able to manage the inventory and make sure that the inventory levels are where they need to be in consideration of pending operating events.

The other thing that hampers us in performing economic dispatch is our plants don't get access to the control signals necessary to perform the functions in the market that need to be performed.

The gentleman from Entergy talked about plants needing to follow load and things like that. To do that effectively engineers need to be able to get a control signal that tells that plant where to be loaded, plug that into the plant's control system, and then have that plant's control system ramp the plant up and down automatically to respond to the needs of the control area. Unless we can get access to those signals, hook them up to our plants and make them technically capable of performing these services, these types of services remain out of reach for us in providing for the needs of our customers.

We think there are plenty of opportunities to look into to improve the economic dispatch in the region and we're willing to help out in however this Panel sees fit to help get to the best answer for the region.

With that, I'd like to say thank you for your time and I welcome any questions you have.

CHAIRMAN KELLIHER: Thank you, Mr. O'Connell.

I'd now like to turn to Carl Monroe, senior vice president, operations and chief operating officer of Southwest Power Pool. Thank you.

MR. MONROE: Thank you, Chairman. And thank you Vice Chairman and the Board for inviting us to speak today.

I've actually been in operations in the electric power industry for about 24 years. And even when I started it 24 years ago I picked up a book and it was written in 1910 about economic dispatch. So economic dispatch has been around a long time.

I've been through the evolution, actually, that went from just straight economic dispatch to using computers for economic dispatch. We used to use old analog equipment for it, and -- for computers for it, and then for security constrained economic dispatch, even to what they call optimal power flow which provides a lot more robust nature of solutions that you need.

Actually to address what goes on within NSPP presently, most of the presenters here have already talked about what economic dispatch -- how economic dispatch is done. And most of it is done by portfolio owners, whether they're control areas or not. If you own a portfolio you're going to try to dispatch that unit to meet your obligations, your load obligation or your purchase or sale obligations, you're going to try to meet that with the generation that you have available.

Mostly economic dispatch, as Mr. Luong said, is performed in somewhere between five and fifteen minute periods. AGC is usually the ten-second period where you're actually trying to adjust between the economic dispatch periods. So I'm going to address really mostly the limitations that are in the present system for providing more efficient use of generation within an economic dispatch framework.

I agree that there's a lot of other areas that you can look at, too, for efficiencies of the use of generation resource, whether it's a year ahead, a month ahead, a day ahead, a week ahead, or whether it is an hour ahead.

Economic dispatch normally refers to that period that happens after the hour ahead is kind of set; your plan is set for hour ahead and then how do you run your generation after that. But there's other opportunities in those others. And if the Joint Board wants to explore some of those others we can talk about unit commitment, we can talk about resource adequacy, transmission adequacy, and a bunch of other issues that deal with everything that you do to prepare to get you up to that hour before when you actually start operating.

There was one question about scope that the Vice Chairman asked about. And scope from the perspective of you really do have to define what the scope is. Is it a geographical area, is it a scope of whose load you're serving, whose responsibilities are you taking into account. So there are some scope issues there that need to be resolved. But I do know that from the limitations of computers and algorithms there's no limitation to the number of units or resources or limitations within the transmission system that you can actually perform the economic dispatch or security constrained economic dispatch on.

The only limitation that we see presently within SPP is the limitation that parties have of how much risk they're willing to take in buying and selling power on an hourly basis. But that's both a commercial risk because of the sensitivity of reflecting what their costs are actually through their bidding process in this hourly market, but also the competition that they have -- how much can they rely on those economic transfers to meet their load requirements. So those are some of the limitations commercially and some of the limitations that come about because of the competition that goes on between these entities that own resources.

Now within the past five years SPP has been encouraged through its membership to start pursuing other avenues that they can use to actually reduce their cost and make it more competitive for them in order to reduce their costs. One of the things we did 14 years ago was reserve sharing. And that's one way that you can actually reduce the -- within the SPP region it was one way that we reduced the amount of generation that our members had to commit to actually be prepared for the day ahead and then for the hour ahead. And through that reserve sharing then they don't have to run as many generators at minimum in order to provide that reserve requirement.

But that's really the day ahead. Really they've been encouraging us within the past five years as looking at what we're calling an energy imbalance market. It's a market, in order to provide this five-minute dispatch every five minutes of a regional dispatch of resources that offer into the market.

Our state regional committee -- regional state committee actually retained a consultant, Charles River Associates, to conduct a study of what a real time benefit would be to an energy imbalance market. And the consultant submitted their report on April 23, 2005. And they determined that the net benefits to the SPP transmission owners over a ten-year period would be about $373 million. And that's about a 2.5 percent reduction in total production costs.

There were some of the same assumptions that were made in that study that some of the presenters have talked about, about a four dollar gas. There is actually an effort now going on to revise that based on more current gas estimates.

Also the benefits that we see in the energy imbalance market is not just a reduction in the production costs but actually an enhancement in reliability. By offering into a regional market, the regional market can recognize the impacts of not only the effect that a generator has on their host control area or host transmission provider, but could recognize limitations that are outside of that area in the dispatch itself, and recognize the interactions that there are between generators as they -- one would raise and one would lower based on those types of costs.

Now only that, there will be a significant amount of data that can be shared between the dispatch because it will be provided by SPP being an independent agency that can be shared within SPP between the market itself and the reliability aspects of what SPP does in order to provide more confidence that the dispatch itself will not raise the risk of reliability within SPP and in fact use the transmission system more effectively. That includes actual study capabilities that we can use out of the market in order to determine what contingencies might be available or might cause problems within the reliability planning.

We do encourage participation in this market. And in fact every resource that is connected to the transmission system that is under the SPP open access tariff will need to register within SPP whether they voluntarily will bid in or not, because when you get into a regional dispatch, just as every control area and balancing authority has to do, they have to consider all the aspects of the operations of everything that's going on within that boundary that they hold.

You've heard some of the aspects from some of the presenters of that from both the way that a control area balancing authority actually does his own dispatch and then what requirements he needs to place on other parties who have either generation or load within that area, usually the scheduling limitations that have been talked about -- in order to be able to determine what actually is available within that area and what the operation of that area will look like so that they can analyze not only how they'll meet their own load and requirements, how they'll meet the balancing requirements of those parties that are scheduling in and out and how they respond to that schedule, but also to look at their transmission effects to.

Now with the regional dispatch we'll be able to do that through the whole SPP region. It wont' be particular to a particular balancing authority. All the region will be able to observe what's going on with every regional entity, whether it's a generation or a load, and then be able to determination the optimal dispatch to meet the imbalance requirements that show up because generation and load don't match in that regard. And that will be what the dispatch is for.

If you -- And it's voluntary for any participant to actually offer their generation into the market. What's not voluntary is the imbalances themselves will carry a price. And that's what the transparency will come from. Transparency will come from the location of those imbalances and what it costs for SPP through its regional dispatch to deliver that energy to that particular imbalance.

We've spent a lot of years in this pursuit. There were a lot of objections that came up. I've documented some of them. We can talk about those if you want to. We've spent a lot of time on educating what a regional economic dispatch market can look like, what are the limitations of it; how does it interact with the use of the transmission system and the capability of the transmission system, how does it interact with the existing parties' rights to use the transmission system and how do you respect those rights even when you're doing a regional dispatch.

Also we have additional steps that our states and members are encouraging us to look at that go beyond just a regional economic dispatch, particularly some of the things that have been talked about in AGC, particularly a regulation market which would provide that type of function for the whole region as opposed to each individual balancing authority. There's the operating reserve that we now offer as sharing. There's actually -- Some of our members see a benefit in showing -- in being able to provide a market for that as opposed to each individual carrying their own, that they could provide a market in order to provide operating reserves.

Also we're -- SPP itself is under two large efforts that we've got going on. One of them is the energy imbalance market which I've described. And I'll go into as much detail as you'd like to with questions about what that represents.

But the other large effort that we're undergoing is transmission expansion, because they both play together. You have to have enough transmission to have an economic dispatch, a regional economic dispatch that provides benefit. But the regional economic dispatch will also show those places where in the transmission system you are limiting the use of the generation and the cost-effective nature of what you can get out of a security constrained economic dispatch.

So those two things actually SPP is pursuing together because we see those two things tied together.

The presence of the market we believe will not only provide the benefit of using more cost effective generation to provide service to wholesale customers, and particularly those wholesale customers that have responsibility for retail load, to provide them a more cost effective way to provide energy to their retail loads. But what it will also do is provide a transparency within the wholesale market so that when you're looking for opportunities within the wholesale market you'll be able to tell from the transparent nature what opportunities there are available and where those are available because the transmission system is very locationally based.

The system that we're building will have locational prices that will help in determining that, in providing that as a transparent function of the market, will provide we believe long reaching effects of that.

So thanks for the opportunity for addressing these questions in the Joint Board. And I'm available for any questions as we go forward.

CHAIRMAN KELLIHER: Thank you, Mr. Monroe.

And now our final Stakeholder presenter -- and correct me if I mispronounce your name -- Kent Saathoff.

MR. SAATHOFF: Very close.

CHAIRMAN KELLIHER: Thank you.

Director of system operations at ECOT. Thank you very much.

MR. SAATHOFF: Thank you, Mr. Chairman. I appreciate the opportunity to address the Joint Board.

In the presentation you have in front of you I have tried to address each issue that was raised in the agenda. In my remarks I'll keep it at a higher level than that. I'd be happy to answer questions on either my remarks or the agenda -- or the presentation, excuse me.

Essentially in ERCOT there are two entities responsible for the dispatch of the system. Those are qualified scheduling entities and ERCOT.

Qualified scheduling entities dispatch their resources to meet their bilateral obligations. Presumably they do it at the least cost, both taking into account the portfolios that they have and also any other offers on the bilateral market. ERCOT will then modify or supplement that dispatch to, number one, meet total system needs to maintain system frequency, and also to manage transmission congestion when our analysis indicates it exists.

We meet total system needs by using the ancillary service capacity that is typically obtained the day before. Those ancillary services are regulation-responsive or spinning reserve and non-spinning reserve.

Now those ancillary services can be self-arranged by the QSEs. Each QSE that represents load is allocated a share of the total system requirement for ancillary services. And they may schedule self-arranged resources to provide their obligation or they can rely on the ERCOT day ahead ancillary service market that ERCOT runs to get their obligation fulfilled.

In addition to those ancillary services we also run a balancing energy market every 15 minutes. And all balancing energy needs in ERCOT -- and balancing energy is essentially the difference between what the QSEs have scheduled in that 15 minute period and what the ERCOT total load is in that 15 minute period. And each 15 minute period we run a balancing energy market to obtain that difference.

And all generation regardless of ownership is eligible to bid into that market and provide balancing energy.

We manage transmission congestion in two ways. Currently ERCOT has a zonal type arrangement where we have five congestion zones. Transmission congestion between those zones is managed by sending zonal balancing energy instruction to those zones to either increase the generation in one zone, decrease it in the other to relieve congestion on that constraint to maintain the transmission system security.

The cost of that movement of generation is allocated to those QSEs that are scheduling across those constraints.

Intra-zonal congestion -- that's congestion within the zone -- is handled by unit-specific instead of zonal instructions. And typically that, the movement of the specific units is compensated for based on a formula that's set out in ERCOT protocols.

There is, as you probably know, a big change that's been discussed for a couple of years -- I think it was mentioned earlier -- in that instead of a zonal market the Public Utility Commission of Texas has passed a rule that says we'll go to a nodal type market by January 1 of 2009. And that would replace our existing zonal system.

The current protocols that are under review by the PUC at this time would have us send dispatch instructions to units specific units based on bid prices.

And essentially we would do a security constrained economic dispatch at ERCOT, although units could still be self-committed by QSEs.

Another feature of the nodal market is going to a centralized day ahead market administrated by ERCOT. Currently there is no centralized day ahead market. Bilateral deals are made by telephone, as was mentioned previously.

One of the questions in the agenda was the benefits and costs of what we're doing now versus before. There was a cost-benefit study done that has also been referenced before -- and I have given you the link there in the presentation -- that quantified the benefit of going from the current zonal market to a nodal market. And it saw a reduction of generation costs of about $76 million a year. That probably needs to be updated also for the rise in gas costs.

As far as the benefit of what we do now versus what we did before when we had ten separate control areas each doing their own security constrained economic dispatch before, is the current arrangement helped facilitate going to retail choice in Texas by combining centralized operation in ERCOT with centralized settlement and centralized administration of customer switching.

One of the other benefits is that now there is one entity in ERCOT -- and that is ERCOT -- that is responsible for maintaining reliability and taking actions to do that. And we've also found that -- we've also, in transmission congestion, we quantify the cost of transmission congestion now so we know what it costs and where it's costing. And that greatly benefits us in planning transmission for the future to take care of that congestion in the most economic basis.

And that concludes my remarks. I'll be happy to answer any questions.

CHAIRMAN KELLIHER: Thank you, Mr. Saathoff.

Let me start off with a few questions and then I'll turn to my Vice Chairman and then the other Joint Board members. And we'll see how it goes.

But Mr. Henry's statement identified a number of operational constraints. I'd like to ask a question of Mr. O'Connell and Mr. Henry.

First, Mr. Henry identified a number of operational constraints that govern economic dispatch including ramp rates, minimum run times, unit startup times, emission limits, planned maintenance schedules and hydro pump storage reservoir limitations.

Do you agree with those kinds of operational constraints, those are appropriate operational constraints? Should heat rate be the only consideration or do those necessarily have to be considered as well?

MR. O'CONNELL: Mr. Chairman, I think you have to consider all of those operational constraints.

There are some practicalities in physically operating the equipment. One of the things that destroys generation equipment the quickest is rapid thermal stresses caused by heating up and cooling off. If you don't give the equipment the chance to get back to a steady state temperature before you begin to heat it back up again you can advance the deterioration of the equipment.

So what you wind up with is once you start a piece of equipment up you can heat that metal at a certain rate of change to get it to that steady state operating temperature. Then you want to keep it at that steady state operating temperature for a lengthy period of time to do what they call heat soak, or to make sure that all of the related equipment gets to the appropriate temperature. And then once you get it there you leave the equipment available to operate as long as the operator needs it.

Once the decision is made to shut it down you have to cool it off at a certain rate of change of temperature to avoid the same types of problems. And then once it's shut off you need to let it get back down to steady state ambient temperatures before you begin the heat up part again.

Where does that come into play? A lot of times, say on a Friday afternoon, you think you may not need the unit on Saturday or Sunday but you'll need it Monday. So you make the decision to let it go on Friday -- say Friday evening after Friday's peak -- or do you maybe keep it around for Saturday because you may need it Saturday. Well, if you need it Saturday you can't shut it down but if you let it go on Friday you can.

So it's these types of limitations on the equipment that really need to be factored in to determine what is the appropriate dispatch level.

With respect to pump storage units, there's different types of pump storage units. I'm most familiar with pump storage units that have what we call daily ponds. And that is, you fill the pond up at night and you completely drain it during the day, and then you fill it back up the next night.

There are other types of pump storage units that are called like weekly ponds wherein you fill it all the way up during the weekend; you partially lower it at night, you pump it back up, you partially lower it more, so that at the end of the week that's all the way empty and you have to fill it all the way back up again.

So there are these practical operating limits that need to be factored into the decision of what resource to operate at what point in time.

But given these constraints, you still want to try to use what's available when it's available in the most effective manner.

CHAIRMAN KELLIHER: Mr. Henry.

MR. HENRY: Yes.

I understand the question was should we consider the other operating constraints.

CHAIRMAN KELLIHER: Right. I mean do you agree those operational constraints are --

MR. HENRY: Yes. I completely agree.

CHAIRMAN KELLIHER: Okay. Short answer. Thank you very much.

I was afraid that Mr. O'Connell would lose. I don't have a "P.E." after my name, so I wasn't sure I was going to follow you.

(Laughter.)

CHAIRMAN KELLIHER: Yeah, the J.D. really -- or the Esquire really is a limitation sometimes.

Now I wanted to ask Mr. Hurstell a question. You pointed out how Entergy has dramatically increased its power purchases but that there's still, say, fifteen percent is old gas. And what's the primary reason why you can't purchase more in lieu of that fifteen percent? Is it, as you say, you identified that a lot of times the bids don't -

- they're block bids; they don't have load following characteristics.

Is that the primary reason why that fifteen percent doesn't shrink, or is it the physical location of those units? They are in effect reliability must-run units? Or is it transmission constraints? What's the primary reason why that fifteen percent remains?

MR. HURSTELL: I don't know if you can say what's the primary reason. Let me give you an example.

When we have reliability must-run units it's not because -- it may not be just because of transmission. It may be because we need it for -- to provide load following. But what we've been talking about is, remember, security constrained economic dispatch.

CHAIRMAN KELLIHER: Right.

MR. HURSTELL: And most of the things you heard was that economic dispatch works; we need to eliminate the security constraint and limit the constraint. And I agree with that.

But the fifteen percent, if you look at it, if we have a generator running because of a transmission constraint then it's operating at minimums in order to supply voltage support. So now we have a unit that's operating on minimum. Well, what's the incremental cost, then, of having that unit serve in a row of operating reserves? It's zero because it's running because of the transmission problem.

So if you say, well, we're going to go spend hundreds of millions of dollars to eliminate the transmission constraint and now you don't have to have it running because of transmission but you have to have it running to provide operating reserves then you haven't really saved anything. Or if you need it to provide load following then the fact that it's running for transmission constraints just means that the cost of load following becomes very low.

So I can't sit here and tell you that transmission constraints is the top priority, load regulation is the second and operating reserves are the third. It's all of those things.

CHAIRMAN KELLIHER: But last year at the Techno conference in New Orleans -- Sandy was there, Michael was there -- I thought Entergy said you purchase about -- there was about a 19 or 20 percent amount of your supply that is now self-generated and that about half of that you could rely on purchased power but that the other half they were in effect reliability must-run units and you didn't see how those could be displaced.

MR. HURSTELL: Well, I didn't do that study but I know what study you're talking about. And I think what they're saying is that assuming that the IPPs offered the flexibility that we needed to provide the reserves and the load following then it's probably ten percent that would boil down to reliability must-run.

So I guess if you look at it like that it's probably -- was it fifteen percent? -- so I guess you could say ten percent from transmission and five percent from the others. But I'm not sure I would define the line quite so brightly.

CHAIRMAN KELLIHER: Okay.

Now some of your written submissions to DOE -- at least Entergy and Duke's written submissions to DOE's survey you both pointed to PURPA, PURPA contracts and made the argument that PURPA contracts are completely divorced from economic dispatch, that you have to take the energy that's delivered.

So that aspect of purchased power is, contrary to what we usually hear when we hear the debate about economic dispatch -- typically the notion is that the independent power facility has got a better heat rate, it's more efficient, but it's not being dispatched. Now the QF seem to be in their own category, though, where they're dispatched regardless of heat rate, regardless of economic dispatch considerations.

MR. HURSTELL: Well, we don't dispatch them, first of all.

CHAIRMAN KELLIHER: Right.

MR. HURSTELL: They just show up.

CHAIRMAN KELLIHER: Right.

I wanted to ask Mr. Henry, both Mr. Henry and Mr. O'Connell, you're both -- you operate in a number of different markets, including the south. Which market do you think you have the best chance of your units being dispatched? Is it ERCOT?

MR. HENRY: ERCOT, yes. Our plants in ERCOT dispatch very frequently.

CHAIRMAN KELLIHER: Okay.

MR. O'CONNELL: Mr. Chairman.

CHAIRMAN KELLIHER: Yes.

MR. O'CONNELL: I don't know if you wanted my --

CHAIRMAN KELLIHER: Yes, please.

MR. O'CONNELL: Okay.

I think that strictly from a location perspective our plants that we have rights to in southern California operate the most. That's more related to their location on the transmission system than anything else.

In terms of the structure and rules associated --

CHAIRMAN KELLIHER: Excuse me. Are they reliability must-run units in California/

MR. O'CONNELL: Yes.

CHAIRMAN KELLIHER: Okay.

MR. O'CONNELL: With respect to rules and organization of the region and things like that, I think that we feel as though we have the fair shot within PJM and its rules are clear, concise, and there's a transparent way to see what's going on and make sure that things happen the way they're supposed to.

CHAIRMAN KELLIHER: Okay.

And both Mr. Henry -- shall I call you Henry the Second?

(Laughter.)

CHAIRMAN KELLIHER: Mr. Sam Henry and Mr. O'Connell identified lack of transparency in the south as a problem for independent power. And Mr. Beam identified this as well. I'm sorry, it was one of either Mr. O'Connell or Mr. Henry and Mr. Beam identified this.

But Mr. Beam pointed out the southeast has a very liquid market. There's no central clearinghouse; that sellers have to rely on phone calls to potential buyers, et cetera.

Now RTOs have pretty good price transparency. But you don't have to be in an RTO region to have good price transparency. The Synergy Hub was an excellent trading hub before the establishment of MISO and currently Palo Verde, Mid-Columbia and Camp are all very good trading hubs.

What's different about the Entergy and Southern hubs? Whey are they much less liquid? For any of the panelists. Can you explain why was the Synergy hub such an excellent source of price transparency and why aren't the Southern and Entergy hubs equally good sources?

Is it the number of wholesale transactions --

MR. SAM HENRY: Yes. I think one is --

CHAIRMAN KELLIHER: -- are much less, or is it that in wholesale is a much lower percent of transactions are reported?'

MR. SAM HENRY: I think one is the size of Entergy given the market, I guess the availability of transmission out of the area. In Synergy you can go quite a few different places and Entergy is pretty much localized to that area. So I'd say that's the two primary reasons --

CHAIRMAN KELLIHER: So what's the solution? If there's a problem in that there isn't a good trading hub, what is the solution? Do you have a proposal on how it could be remedied or it's just a problem we're going to rue.

MR. SAM HENRY: Well, I think, yeah, the introduction of the day ahead market would go a long way toward developing that. By day ahead, not just the Entergy auction, but I guess an area where -- The scope of the dispatch has extended beyond just the Entergy system.

Now I think, just hypothetically, if there's a vertically integrated utility that has both merchant generation and transmission I suspect that what happens is that the generation side comes up with their optimal dispatch of generation. They had the information off to the transmission side. And then it becomes non-transparent.

If the plan of generation doesn't work and transmission has a problem it's not clear if the transmission guys just say, 'Make these changes so that the power will flow: Bring Level A down and bring Unit B up,' or if they go back and say, 'Just try it again.'

To other market participants who would like to participate, who perhaps could even solve that problem, we don't have an opportunity to participate in that because the scope is limited just to the utility itself.

MR. O'CONNELL: Mr. Chairman.

CHAIRMAN KELLIHER: Yes.

MR. O'CONNELL: From Williams' perspective I think there's two aspects we need to look at. One is the transparency related to the congestion management and transmission system operation.

I think one of the things you pointed out about Synergy that we don't see in the southeast is that in Synergy area the operation of the transmission system and the congestion management practices were rather transparent.

That gave merchants a good degree of comfort that if they set up a particular transaction that it was going to go through, or that if they were contemplating setting up a transaction for tomorrow that the information -- that, A, they were seeing information and that, B, the information they were seeing was rather reliable and that the transmission owners would be operating under those guidelines.

The second thing about Synergy was there was price transparency in terms of what is the market value for energy for that particular period. I think that in the southeast we're struggling with both things.

We don't have transparency in the congestion management practices; they're highly inefficient. And I think someone called them arbitrary. And the other thing is we don't have good liquidity in the market, and that liquidity is undermined by the lack of transparency in the congestion management practices.

CHAIRMAN KELLIHER: But the Synergy hub was liquid before the establishment of MISO. How was Synergy's operation of its transmission system more transparent than Entergy or Southern's?

MR. O'CONNELL: Well, I think that some of the things that we saw was --

CHAIRMAN KELLIHER: This is Synergy under the O, Synergy pre-RTO, why was its system more transparent?

MR. O'CONNELL: I think that things that we saw was in the Synergy and surrounding area the ATCs that were published were better ATCs.

CHAIRMAN KELLIHER: Was the methodology different, the ATC calculation methodology?

MR. O'CONNELL: I never actually dug into the methodology so that I can make an adequate comparison between what methodology was used up there.

I think another thing was some of the transmission systems up there were a lot more robust than some of the transmission systems in southeast. With the AEP system connecting to two dozen different utilities it gave you the ability to move energy from a broad range in the area.

So I think it was a convergence of a lot of things that wound up making that happen. But those are the observation that we saw in our operation in that area.

CHAIRMAN KELLIHER: Okay. Thank you.

MR. HURSTELL: Mr. Chairman, I would like to clarify.

CHAIRMAN KELLIHER: Yes.

MR. HURSTELL: We've had comments about the transparency on congestion management. And let me assure you that Entergy, the generation side, receives no more information about congestion management than any IPP. We get information about whether transmission is available from our generation to our load just like any other IPP. The difference is is that we have 84 generators, so we can get a lot more information just because we have a lot more generators. If you only have one generator you're only going to get information about that one.

So I just don't want anyone to think that there is some discrepancy between the information that different generators get based on whether they're an affiliate of the transmission company.

COMMISSIONER CALLAHAN: To that point, should we move to a more transparent market so that other one generator got the same information your other 85 did, so that everybody's getting the same information and everyone knows the condition of the whole system.

Does that make the system better and will that allow us to do more efficient economic dispatch?

MR. HURSTELL: Commissioner, I think then the issue boils down to who benefits from that.

Remember, when we put in our transmission requests we're generating on behalf of our customers. And what we're trying to do is generate -- dispatch our system as economically as we can to get the lowest cost for our customers that we can. And on occasion transmission may come back and tell us, 'You can't do this. You have to buy from one of these two IPPs or sometimes you have to go buy from this one IPP.'

Now if you think that it's going to be beneficial to our customers to provide information to that IPP that transmission has told us that we have to go buy from that IPP, then we should share the information. And I'm just not sure that when -- that transmission should be telling generators that customers need to buy from you.

Just by the same token, there may be occasions when Clarksdale may need to buy from Entergy and transmission shouldn't be telling us that Clarksdale needs to buy from us.

So remember, there's a third party here we talk about. We've got transmission, generation, and you have the customers. And we are representing the customers when we put in our transmission requests. We're not really representing the generators.

COMMISSIONER CALLAHAN: But we hear Mr. Priest and Mr. Beam talk about the problem with trying to negotiate bilateral contracts because of the fear of having the availability of transmission.

Would a more transparent transmission congestion management help you scheduling and bringing more efficient -- more economic generation to your customers?

MR. HURSTELL: We have the exact same situation. We may be entering into an economy transaction but we're not sure whether or not the deal is actually going to go through. So what we do is if it's 100 megawatts on 20,000 megawatt system, well we can afford to lose 100 megawatts of an economy transaction; we can replace that. But if it was 2,000 megawatts we probably wouldn't do it then because we can't afford t lose it.

But the important point I'm trying to make is that we have the exact same problems in terms of not knowing whether or not economy transactions are going to remain in place.

MR. PRIEST: There may be one difference. He said occasionally they couldn't do the transaction; frequently we can't do the transaction. And we're not dealing with 1,000 or 2,000 megawatts; we're dealing with 20.

MR. BEAM: I think it's partly a matter of scale. I think we're a lot more dependent on transactions with third parties than an Entergy is. And I think that the transmission constraints are a major part of the problem of us being able to identify and access low cost power supplies.

I can't speak to why the south is different from Entergy. I feel like, having made the point that there's no centralized clearinghouse, I should be able to offer a solution.

We do operate in PJM, and I know that PJM has -- since we've joined PJM for ten percent of our load many of the problems that I've identified have gone away. Now there is an efficient market there that resolves a lot of these problems of matching up generators and loads.

On the other hand PJM has other issues. It is well documented that there are high costs of implementing PJM. I know our transmission costs have gone up. So we're still -- The jury is still out for us as to whether that market is the solution that we're looking for.

CHAIRMAN HOCHSTETTER: Well, I was just curious as to how the -- and if this is an inappropriate question to ask because these are pending dockets just tell me so.

But I'm curious if the ICT proposal that Entergy has proffered, as well as the Duke ICT proposal, would solve, you know, any or all of these problems that have been identified to day, and to what extent would an ICT sort of arrangement -- as opposed to an RTO arrangement -- address some of these problems of transparency and, you know, confidence and then the availability of transactions to occur in a more liquid fashion.

Is that an okay question for me to ask or not?

CHAIRMAN KELLIHER: It depends on the answer, I think.

(Laughter.)

MR. HURSTELL: Can I answer by the intent, maybe? The intent certainly is -- Yes, that's the intent of it. And the main -- From our perspective the main benefit of the ICT is -- and I want to correct one thing that Mr. Priest said: Entergy does not have a priority in the ICT; all network customers are treated the same.

The idea there is to give transmission the information regarding the economics of different opportunities so that they can do a security constrained economic dispatch that minimizes the costs for the control area. And Clarksdale and NYGen would be on the same footing as Entergy.

So it's the intent -- It's our belief that the ICT will facilitate more economic transactions. And we wouldn't run into the problems that both Mr. Priest and I have described.

CHAIRMAN HOCHSTETTER: Now what do the TDUs think?

MR. PRIEST: Well, since I am the customer -- my attorney has advised me I can't go into any real detail on that -- but if the ICT is truly independent the answer is it probably would.

MR. BEAM: And I can't speak to the Entergy ICT.

But I would say that to have an independent entity, that entity needs to oversee and ensure the independence of the planning and operation of the system. I think just having an entity that comes in and recreates functions that are currently being done by the utility are not necessarily beneficial. It needs to ensure that there's a broader scope of independence brought to the planning and operating processes.

MR. MONROE: Can I say something?

CHAIRMAN KELLIHER: Sure.

MR. MONROE: I'm not going to wade into the case or anything.

The ICTs have been structured mostly around the independent provision of transmission service and Entergy's also in the ICT offered the weekly procurement process.

But speaking about economic dispatch in particular, you still have the situation where every party is trying to compete against each other in that arena for the transmission and you're not optimizing the use of either the transmission or the resources in order to meet the requirements of what there is within the load. So it does provide an independent framework to have somebody who is independent of the owners of the transmission looking at that process for granting transmission service, but it doesn't deal with these issues having to do with the economic dispatch of the resources within that area.

CHAIRMAN HOCHSTETTER: Can I ask Carl a follow-up question?

But the -- with respect to the independent transmission planning functionality that the ITC would provide, that entails optimization of the incremental transmission construction for reliability as well as economic upgrade purposes, from my understanding. And so --

MR. MONROE: That is correct. From the transmission expansion side, yes, it provides that.

CHAIRMAN HOCHSTETTER: So presumably if you had optimization in the transmission planning and construction side of the equation and you optimized the upgrades needed for reliability and economic transactions, economic purchases, then perhaps that could ameliorate some of the concerns on the other side of the equation in terms of when you're actually doing economic dispatch. Is that a fair assessment?

MR. MONROE: I would say that's a fair assessment. It depends on what is done with that information. Of course for reliability, everybody is key on making sure that the system can reliably deliver the generation to the load. But it doesn't say anything about whether it provides the most economical generation to the loads. That's where the ICT in the way it's being proposed at least in Entergy and some others is where they could propose things that would -- transmission expansion that would reduce the impediments to providing cheaper generation to load.

But John did also bring up another issue that really needs to be considered. And this is that in the larger region of dispatches there's always -- you always need to have somebody monitoring to make sure that the market is not -- that there is not somebody who can unduly exercise market power. And I think that was the concern that John had. And as long as you create that situation where you have a robust market of wholesale, you still need to have that party that's monitoring the provision of that wholesale energy so that nobody does have market power abuse.

CHAIRMAN KELLIHER: I had a question for Mr. Saathoff.

There was -- Center Point had some comments in response to the DOE survey on economic dispatch. And they were, at least surprising to me, surprisingly critical of ERCOT. And they argued that ERCOT's economic dispatch had -- as a result of ERCOT's economic dispatch frequency performance has suffered.

Is that something you've heard before and do you have a response for that?

MR. SAATHOFF: Yes. We have a task force that's looking at that issue. And historically it's been mixed, from before the old tin control area operation to current, we have had improvement in response to system disturbances, such as loss of a large unit. We seem to be able to recover quicker.

But the real time frequency, it's been more ragged since we've gone to our current mode of operation. And we have a task force looking into that to determine exactly what's caused that and how we can improve that.

CHAIRMAN KELLIHER: Thank you.

Jimmy.

COMMISSIONER ERVIN: Mr. Chairman, I sometimes find -- a lot of times -- that when I listen to panels like this the questions I really want to ask are definitional as much as anything. And so I really have got a couple of them just so I make sure I understand what folks are telling us.

I do appreciate all of you coming to be with us this afternoon. One of the problems that those of us who have J.D. after us instead of P.E. tend to suffer from is it helps me a lot of times just to listen to people talk for a while. And so I really thank all of you for coming and furthering my education this afternoon.

Mr. Sam Henry, I guess the first question I want to ask is -- you didn't exactly say this and so I don't want to put words in your mouth. But it seems to me that you came fairly close to saying that economic dispatch was not performed in the southeast. Did I get an implication that you meant to leave with me, or am I just hearing you wrong?

And my follow-up question is if I got it right then tell me what you mean by that term because my suspicion is if I am right you mean by it something different than the way some other folks use it.

MR. SAM HENRY: Yeah, economic dispatch I agree with the definition stated by Mr. Luong earlier. And I would say in the southeast it's a question of sort of transparency that the scope --

COMMISSIONER ERVIN: And that's a great segue to another question to another question I was going to ask.

MR. SAM HENRY: Okay.

COMMISSIONER ERVIN: Which is everybody loves to say we want transparency. But that means different things to different people.

And so in answering my question if you could tell me what you mean by transparency I think that would help too.

Now I'll be quiet and let you talk.

MR. SAM HENRY: I think there's a question about the scope of: are all of the resources within the geographic area considered when economic dispatch decisions are made. It appears to me that the scope is not all IPPs within certain areas.

COMMISSIONER ERVIN: And you say that because?

MR. SAM HENRY: We have a plant there. I'm surprised it's not dispatched more often.

COMMISSIONER ERVIN: Okay.

And I'm sorry. I apologize for keep interrupting you.

MR. SAM HENRY: No, that's okay.

And as far as transparency, I think that's -- from time to time we experience transmission constraints. When we look at the conditions that are apparent to us, like the weather, the availability of transmission on the website, we're surprised sometimes. We'll call Entergy and say, you know, what gives. And in several instances after reviewing we find that the transmission as available and it becomes apparent to us.

So it's sort of a timing thing. Eventually it gets worked out. But the speed of the dispatch and the availability of the information is not there.

The information about the availability of transmission is not complete. It's either available or not. And when it's not we'd like to know why not.

COMMISSIONER ERVIN: Okay.

Mr. Beam.

MR. BEAM: If I could take a stab at that.

I think from our perspective --

COMMISSIONER ERVIN: I was headed your way so I appreciate you grabbing the mic.

MR. BEAM: From our perspective -- I mean we feel like Duke Power does economic dispatch of their system, Progress Energy, Southern Company. And they do it very well. But I think the issue is that they do it on a company by company basis or control area by control area basis. And there are entities such as ourselves that are not included in that dispatch. And as a result of that there are economies that are lost.

We perform economic dispatch of our system, such as it is. We don't operate a control area. We do have a portfolio of resources that we try to optimize to minimize the costs to our customers, but that's a fairly limited portfolio.

If economic dispatch was done on a broader scale where all entities were included in that dispatch then I think you would wring out economies that you can't get by just--

COMMISSIONER ERVIN: And by all entities you mean all LSEs.

MR. BEAM: I'm sorry.

COMMISSIONER ERVIN: And by all entities you're meaning all LSEs in this instance.

MR. BEAM: Yes.

COMMISSIONER ERVIN: Okay.

Now I'm sorry. I've found if I don't make sure I follow people by interrupting them I lose them.

If we were -- if you were given the authority -- this was the question I was going to ask Mr. Priest but I'd be interested in hearing your viewpoint on it too because Mr. Priest talked about a need for centralized dispatch I think in one of his comments:

If you were to design the system yourself how would you design it. And I'll take that from either Mr. Beam or Mr. Priest, who wants to comment on it, but I was going to ask it of Mr. Priest.

MR. PRIEST: I'm not sure how I would design it, but --

COMMISSIONER ERVIN: And I'm not talking real specific.

MR. PRIEST: Yeah. In generalities, I think economic dispatch is being done today by a lot of folks is still based on the 1910 book that Carl talked about. I've been around a while, but not quite that long. Okay?

(Laughter.)

MR. PRIEST: I spent a number of years in Florida before I moved to Mississippi. And I'm sorry there is no Florida Commissioner here today. But they had a wonderful experiment going --

COMMISSIONER ERVIN: There's actually one in the back of the room who could --

MR. PRIEST: Hiding.

(Laughter.)

MR. PRIEST: But they had a wonderful experiment going on for a while that worked quite well.

In the late '70s they started what was called the energy broker, which was an hour economic purchases. Any utility could participate. You had to have bilateral contracts with whoever you get matched up with. But you put in a quote to either buy or to sell, the number of megawatts and a rate per megawatt hour, incremental and decremental cost. And then there was a high-low match done and the split the difference. So if I'm looking to buy and my incremental cost to buy at the generator is $40 and John can sell for $20 and we get matched, the transaction price is 30. He makes money; I save money.

It was a problem doing it just on an hourly basis. I left down there in the early '80s and they were looking at designing a model where they could do a similar method on weekly transactions.

But this started in the late '70s and there was no fancy computer equipment generally available then. It was run on a big mainframe in Akron, Ohio -- I think it was in Akron. Forty minutes after the hour we'd put in our quotes and 48 minutes after the hour they'd give us a schedule. At the top of the hour we'd make the adjustments to it. It was simple and inexpensive. And seemingly, everybody benefited from it then.

COMMISSIONER ERVIN: This was a voluntary arrangement?

MR. PRIEST: Yes.

COMMISSIONER ERVIN: Okay.

MR. PRIEST: And it may have been the first marked based -- quote, unquote -- marked based type transactions approved by FERC. But I don't know that it has to be extremely complicated to be workable.

Clarksdale has been a member of SPP since 1969, or affiliated with it. Entergy pulled out of SPP in '97. I think it was '97. So we're no longer connected with SPP even though we're still members of it. So we can't take advantage of the markets that are being created there.

We need to be able to get to markets. And right now we can't.

MR. BEAM: I'd add to that, I think a similar system was in place in Florida called the Florida broker system that may still be in place today that's very similar to what Mr. Priest was talking about. And what these type of programs do is they match buyers and sellers for transactions.

I think for a true economic dispatch where all generators are in a pool and dispatched economically -- as they would be for, say, the Duke system -- then you get into a lot more complicated arrangements with how you compensate people, how you determine whose generation contributed what, what the costs were, and what people should be paid. There have been attempts to do that in power pools like PJM used to be, and they were very complicated, difficult systems to administer. So there's no easy solution to a true economic power pool or dispatch.

MR. HURSTELL: If I may, in the early '90s a group of utilities including IOUs, cooperatives and municipalities worked on a program called AIM, automated Interchange Matching system that was -- we essentially wanted to take the Florida program and expand it to the southeast. And I agree with everything that Mr. Priest and Mr. Beam said about how successful at least the 40 utilities believed the Florida broker system was, and we tried to transfer it.

The problem we'd run into, though, was when you get to a bigger area transmission issues come into play as to can you match up an IOU like Entergy with a municipality in Georgia, is there transmission. But the biggest issue was when you have merchants come in -- and we had merchants and marketers come in -- is you start having some players bid their cost and some players bid market. Well, is that the right -- Do you do split the savings when you have some people bidding cost and then some people bidding market. And it just got to be complicated.

And then you get into a situation of, well, some people had market based rate authority to sell in some areas but not in others; so when they put in their bid did they match up with someone in an area where they could charge market based rates or was in it an area where they had cost based rates. And this was in the early '90s when all this was happening.

So we tried to take a system that was in a small geographic area with a homogeneous set of participants and bring it to a much larger area with a very diverse set of participants and we ran into significant difficulties.

So we tried to do that. And I'm certainly not opposed to trying it again because the world is certainly different than it was in the early '90s. But we have made that effort before.

CHAIRMAN KELLIHER: Are there any other questions? We have a couple electronic Commissioners here with us and I don't know if anyone on the phone has a question they want to ask.

(No response.)

CHAIRMAN KELLIHER: No?

Any other members of the Joint Board want to ask some questions?

You do? Sure.

COMISSIONER CALLAHAN: Mr. Henry the First. Mr. Hurstell did a very good job showing some of the problems Entergy has trying to fulfill that last ten to twenty percent of energy that may be displaced because of dispatch problems in the products being offered.

Does Duke run into those same problems?

MR. SCOTT HENRY: Duke's generation portfolio is a little different than Entergy's in the fact that we do not have any base load or intermediate load gas fired generation. All of our intermediate and base load generation is either hydro, nuclear or coal. We only use gas fired combustion turbines on our system.

So that creates a different cost curve that is available for economy purchases to happen. So we don't typically experience those type of problems, I don't think, that Entergy has had because we don't typically have transmission constraints on our system that would inhibit the ability to purchase from IPPs on our system. Typically we just have not in the past had those type of constraints.

COMMISSIONER CALLAHAN: Okay.

MR. SCOTT HENRY: We are generally not constrained.

COMMISSIONER CALLAHAN: To Mr. Henry and Mr. O'Connell: You've heard Entergy -- and I've for the last three or four years as different merchant operators have come to Mississippi to talk to the Mississippi PSC, you know, why can't we get our product to market, why can't we get dispatch. We hear the same thing from Entergy. They're giving us a product that we find very complicated to use as -- I think he did a good job in his description showing how they dispatch versus what you're bidding and what you're offering.

Have you tried to work with Entergy or anyone else to try to mold or put out a product that would meet the needs of the companies and help them to get your power into the system? And if not, why not?

MR. O'CONNELL: Mr. Vice Chairman, I'm not aware of all the activities that our origination group has had with Entergy in terms of offering products and trying to sculpt a product that fits Entergy's needs.

But I can say that, on behalf of my company, that that's one of our specialties. That's why we have the deal we have with the four electric membership corporations in Georgia. That's why we have the deal we have with the

Allegheny Electric Cooperative in Pennsylvania and why we have the deals we have with some of the entities in California. So I think it's something that our organization is well equipped to perform.

One of the challenges we have is that we don't always get access to the same kinds of control signals that the utility plants get. For example, to follow load you need what engineers call dispatch lambda signal, where that tells you where to move your unit. Well, if I can't get access to that control signal I can't provide the same service that the utility plant is providing.

So when the gentleman made the comment about providing things like that to non-utility entities to allow them to provide these services I was thinking to myself, gee, I hope there's a transcript of this conversation here because I want to take that back to them and say, 'well, we're willing to do this; let's sit down and talk.

I will be in contact with our origination staff some time tomorrow morning to talk to them about what we can do and try to piece something together. So that given access to the infrastructure that we need to provide that service, we will come to the table with a product that meets those needs.

MR. HURSTELL: Commissioner, if I may.

COMMISSIONER CALLIHAN: Yes.

MR. HURSTELL: I don't think it's a question of whether they are capable of providing the service. They may not have - the equipment may not be installed, but they can install them. And they certainly have the capability to match the load.

We have run tests with two IPPs to see whether or not we could integrate them to provide the load following. And both of the tests showed the same thing. It is that they are physically capable of providing it. And I think the IPPs in question wanted to provide it. The problem they ran into is they only had a single gas pipeline.

Remember, all of this is integrated. So if you're going to provide load following you can't buy gas on a ratable basis. You can't buy a flat amount of gas. You've got to have flexible gas supplies.

And that's why all of our plants have two, three, as many as 14 gas pipelines going into a plant, so we can acquire a flexible gas supply to allow our units to ramp up and down without committing to gas, whereas I think most of the IPPs, I think in an attempt to keep their costs -- their construction costs down, they have a single pipeline or two pipelines going into their plant. And I'm not saying every IPP does; but I'm just saying in general they have one or two. So even if they have a desire to offer the service electrically they can't get the gas deliveries to match up to their desire.

So it just goes to show -- somebody made the point earlier about the integration between the gas and the electric markets. Well, load following has -- A generator's ability to provide load following service is dependent upon its gas supply.

COMMISSIONER CALLAHAN: Mr. Henry, did you want to answer or respond?

MR. SAM HENRY: Yes. Our plants have the capability of delivering AGC type products so I think we will be following up on that.

We do have a single pipeline connection at that point but we have the access to gas storage which allows us to manage those fluctuations. So we'll see if we can't have a further discussion with Entergy.

CHAIRMAN MITCHELL: Mr. O'Connell, I wanted to ask you: Why would you think that a brand new plant with a lower heat rate would be cheaper to operate and be dispatched before an older mostly depreciated plant that is less efficient, assuming each plant pays the same for the price of the gas?

MR. O'CONNELL: The issue of whether the plant is depreciated or not doesn't really come into the picture if really what you're looking at -- Given access to the same price of gas, a newer plant with a lower heat rate is much more efficient and should operate in a well structured economic dispatch program before older plants that have higher heat rates.

In general some of these older plants are built with boilers that produce steam and that steam turns a steam turbine. The heat rates for those types of plants are generally between 9,000 and 9,500, whereas if you look at some of the newer combined cycle plants that are based on two gas turbines the heat rates for those are around 7,000. So in essence you wind up burning a lot less gas to produce the same megawatt hour. And that's why you should expect them to operate before the older plants.

Now you may have a situation, depending on maintenance costs and how those are treated, that one kind of plant runs harder. Maybe they go to an operating environment where they're using up more of the useful life of the equipment more quickly. And as a result you may see differences between what that one plant's owner will do versus what another plant's owner will do.

But all things equal, you should see a plant with a lower heat rate operating before a plant with a higher heat rate. And that's one of the smell checks that we do in the industry: We ride around and there's one situation that I saw when I was living out in Oklahoma that there was a utility plant sitting right next door to a non-utility plant. And you'd drive by that location day after day and you'd see the utility plant running but the merchant plant not running. And, you know, those of us in the competitive part of the industry would just scratch our heads and wonder why.

Now had we had an ownership interest in one of those plants I think that we probably would have been trying to ferret out the answers to those questions.

COMMISSIONER ERVIN: To go back a little bit to a discussion that we were having a second ago with respect to the AGC issue and others, Mr. Henry of Duke -- I can't get straight who is one and who is two here -- but you all, if my memory is not failing me, have a longer term contract with at least one merchant unit. And I'm assuming you dispatch that unit like you dispatch your own.

Can you tell me a little bit about your experience under that arrangement, how it works operationally and otherwise?

MR. SCOTT HENRY: Yes. Over the years we've purchased from all of the IPPs in our control area, in our balancing area. As I indicated, up until fairly recently those generation resources were all combustion turbine resources, which is utilized predominantly for peaking capability.

Those contracts were structured in a manner that typically required that Duke schedule the use of those resources on a day ahead basis. That is typical of how a merchant generator structures deals so that if they were not called upon on a day ahead basis they could then engage in marketing activities to find possibly a sink or a load to serve with their resource on a non-firm basis.

That activity in and of itself is a limitation from a market -- a market limitation that puts a constraint on those of us who dispatch those type of resources on a shorter term basis. Duke would actually dispatch its combustion turbines, if needed, on a 15 to 20 minute basis for those that we have fast-start capability.

So what we try to do to compensate for that is we in our contracts have now asked for the ability to call on firm purchases, long term purchases on less than the day ahead notice, but we take the price risk associated with the -- typically we would take the price risk associated with the fact that the supplier may have already found another purchaser for that resource and therefore we would have to take that risk.

So in many cases some of the market limitations that exist do not provide what I would call comparable usage from an operator standpoint of the owned resources with the purchased resources. Over time, though, I think, if the value is there from -- if the merchant generators see the value there they'll try to find ways to be more flexible in their operation so that things can be done on a shorter-term basis.

In direct answer to your question, those generating units do not have AGC -- are not typically AGC-capable. And Duke has all of its generation units with AGC, so there's not necessarily a great value for Duke to have -- well, I shouldn't say -- not all of our -- but we have a number of our generating units who have AGC and there's not a significant value to have a purchase contract with AGC to our customers because we can clearly handle that obligation.

MR. MONROE: I think part of the problems that IPPs are having in some of the areas is the access that they have not just to like in Entergy the weekly capability to be selected, but also a daily and an hourly and a minute by minute selection in order to be able to be dispatched. And if they're looking at it from their perspective as bidding into a weekly market, there a lot of risk that they have to take into account in their heat rate bid. Even if they're not taking the fuel risk they may be taking other risk into account in the heat rate.

So the heat rate is not going to reflect exactly what they can burn; it's going to reflect their perceived risk in bidding into the market too, and the products that they have to provide in that too, where if you had a day ahead or an hour ahead they might -- there's less risk in what they would be bidding in that.

Particularly if you're talking about the gas day, if they have to nominate the gas day it would seem like to me a day ahead market would be of great benefit because then they would know by the time the gas day came along what type of gas they would need to buy and whether it needed to be ratable or not, because in a lot of the instances from what I've heard in the gas is you buy a daily total and you can use it whenever you want to during the day.

So they could make a better bid into the gas day if they had that day ahead perspective of whether they'd be selected in some type of market or some type of procurement processes as Entergy does.

CHAIRMAN KELLIHER: Any other questions?

Sandy.

CHAIRMAN HOCHSTETTER: I just had a quick follow-up -- one for you, Carl, in terms of a day ahead market.

What kind of an expense would we be talking about for a day ahead market? I mean, as a for instance, if that was something to be added to the list of ICT functionalities, what, you know -- and thinking of it in the overall construct of a cost-benefit analysis, what would be your guesstimate?

MR. MONROE: Well, adding it to the weekly procurement process doesn't seem to me to be a bigger issue. The biggest issue there is being able to handle all the inputs, the algorithm and everything that you would use. It's very similar to what you do on the weekly basis but you do it for just one day as opposed to the whole week.

So within that -- in the Entergy ICT it doesn't seem to be that big of a deal.

There are limitations, just to speak for John because I saw him over there grimacing, but just to speak a little bit -- and he can answer into it -- but there is a significant amount of effort that you have to watch when you're doing a day ahead, too, that deals with whether you can actually pick up a product at that point, because at that point there's some things that you just can't make a decision on, like if you have a unit, as Mr. O'Connell talked about, that takes a while to turn down or takes a while to turn up, the day ahead you can't make that decision.

But the only way you can find out where those decisions need to be made and the economics of those decisions is to actually do that daily and see where you could build more capability either into the generators or into the weekly procurement process to give you more benefit.

COMMISSIONER CALLAHAN: This is a question that -

- I'll start with Entergy and Duke and then probably everybody I'd like to hear answer it before it's all said and done.

But when you're doing your dispatch decisions and you're looking for energy out there that's not your own plants. I've been to The Woodlands and looked at Entergy's; I've been to Birmingham and looked at Southern's. There's a lot of trading going on as far as companies calling you and saying, 'I've got this product' and you're comparing what you've got and how you can turn the ramp up.

The last couple of years, especially when we had the meetings in New Orleans and Jackson and finally in Little Rock on your independent coordinator transmission, transparency kept raising its head. We need a more transparent system. And we've heard that mentioned here today by the parties.

Would it be beneficial to Duke and Entergy if bids that came across your system for power were posted or put somewhere so everyone could see that Duke just bought this bid at this price and these guys might say, 'Hey, you know, I think I can beat that; let me get on the phone and call them for the next hour or the next day and say if that's what you want I can provide that.'

Just from my standpoint -- again with the esquire behind my name and not the P.E. -- to me that makes a lot of sense. I mean how can these guys know what to give you if they don't know what you're paying for in the market. And how can Mr. Beam and Mr. Priest have any idea of what's going on out there.

It seems to be a very closed system. And I can see where -- understanding your limitations, but also understand their frustrations. And I would think it would benefit everybody if we knew what power was trading for and what you were buying and they could see and maybe they could craft a product that could meet your needs. And then you could have the guys kind of caught in the middle get help from that, too.

So I just would like, you know, kind of the whole panel's input on if we had a more transparent system and how would it affect everybody's business.

MR. SCOTT HENRY: I think it's already been mentioned that it sort of works both ways.

For vertically integrated utilities, because of the public information that is out there, it's not too difficult to know where we might be in our cost curve. And if we're out there looking and getting information about how we're bidding and the bids that we might accept, it doesn't take long for market participants to know exactly where we are in our stack. So in the end our customers don't always get the best value that they could because if someone knows where are in our stack they'll just go right underneath that. We may be at an incremental cost of $40 and if they know that's where we are they'll come in at 39 whenever -- if they didn't have that information they may have come in at 30. And so our customers have actually lost nine dollars.

So it actually goes both ways. To a large extent I think those of us that are subject to --

COMMISSIONER CALLAHAN: Well, now let me clarify something so that we know we're talking about the same thing.

MR. SCOTT HENRY: Okay.

COMMISSIONER CALLAHAN: I'm not talking about necessarily your cost. I'm just talking about purchases you make on the market, whether it be you or whether it be any Entergy that comes across your system.

You know, if North Carolina Electric bought from SUEZ, you know, whatever they paid for that megawatt hour for that time period would be posted so everybody kind of got a feel for what power was trading for out there and how you could meet it or make it or get on.

It's not necessarily what you're doing. But if you buy anything or if anything comes across your system as a whole it would be posted to give transparency. How would that affect you?

MR. SCOTT HENRY: Well, Commissioner Callahan, I've got P.E. behind my name and not an economics degree.

(Laughter.)

MR. SCOTT HENRY: But the economists would indicate that in theory if we have an efficient market then we would be bidding our incremental cost. And so if the market is indeed efficient then our bids would reflect our incremental costs, and therefore that's what we would be bidding.

COMMISSIONER CALLAHAN: John.

MR. HURSTELL: I think from Entergy's perspective what you're talking about is publicizing what we are paying for power. And if you're going to just post prices for Entergy -- I recognize there are other entities inside of our control area, but we are the lion's share of it. So if you have information as to what Entergy is paying for power then it's hard for me to imagine how that's going to benefit our customers.

I'm trying to --

COMMISSIONER CALLAHAN: Well, I'm not talking about just Entergy. I'm mean everybody -- I mean Cleco, everybody.

MR. HURSTELL: I realize that.

COMMISSIONER CALLAHAN: Everything that came across your system would be posted.

MR. HURSTELL: All right.

But I'm trying to think of another industry -- you know, GM. Does GM publish instantly what it pays for the raw materials that go into its products, into its cars? I don't think they do. I'm not an expert, but I don't know of any other business that publicizes what it pays for the raw materials that it uses to provide products to its customers.

VOICE: I'll post them tomorrow.

(Laughter.)

MR. BEAM: What about the NYMEX for gas? I mean we know every day what gas is trading for today, tomorrow, six months in the future.

MR. HURSTELL: But what you have at NYMEX is you have large numbers of buyers and a large number of sellers. Here you don't have individual entities -- you don't have Exxon coming out and saying, 'this is what I -- this is the NYMEX contracts that I transacted today.' You don't have Intrastate Pipeline saying, 'Here are the NYMEX contracts that I entered into today.'

So while you know what is going on in the market, you don't know who it is, you don't know what positions they're taking. If we start publishing the prices that we pay for energy and the magnitude that we're buying, we believe that it's going to be more detrimental to our customers than beneficial to our customers. And we see no reason to do anything that's going to be more detrimental than beneficial.

COMMISSIONER CALLAHAN: Mr. O'Connell, Mr. Henry, do you have anything to add?

MR. SAM HENRY: Well, yes. I think it would improve the transparency if we could get a better idea of what the market prices were.

MR. O'CONNELL: Commissioner Callahan, I think that there are two separate issues here. What is what are the effects of transparency, and then how do you apply that over a geographic scope so that you don't push any one entity into a less preferential position.

I think if you want to look at what the effects of transparency are and you have some spare reading time, PJM just published a study this past week that talked about the economic effects of expanding its footprint from its original footprint up to the footprint it has today.

I had a chance to skim the executive summary the other day and I think they were quoting a number of $500 million a year of savings over that expanded footprint. That's just over the expanded footprint and not about over the original footprint.

What the costs were, I think that may be available publicly. Or if not, I'd be willing to help you get it through PJM. I'm on the PJM finance committee and I can get that information through their CFO if that's necessary.

But I think this is the scale of the type of savings that are available and can be achieved if you get a broad enough region together that's willing to try to figure out how to optimize their performance to achieve that.

So I think that's what you can gain if you want to go to that direction. Understand that from regional perspectives there are certain regions that may feel as though the costs or other considerations may not be worth going to that degree. And I think that in that situation there are lesser alternatives that may bring the lion's share of that cost savings. But I think it's out there.

From a merchant's perspective all I can say is that when you see a price you start thinking, 'well, how can I beat that price.' And sooner or later you come up with a good idea that will be a robust proposal that will be a more attractive product than what's being offered today.

So it's kind of one of those things that goes back to the field of dreams: If you build it we will come.

MR. MONROE: I wanted to get back to your scope issue. And I think that Mr. O'Connell brought that up.

But generally, to me, you have to -- when you're publishing transparent prices you're publishing them to enhance competition. So at the same time that you're trying to make something workably competitive you also have to monitor how the parties themselves are affected by that both from a competitive standpoint and from a market power abuse perspective. And I think that's what Mr. Hurstell is concerned about, that by publishing this information in a non-competitive environment that it does not provide benefit to the customers beyond that.

Now the reason that we're setting up the imbalance market in the way we're setting it up is in order to give those two things: to give transparency and to have the monitoring and mitigation that's necessary to prevent market power abuse in that.

COMMISSIONER CALLAHAN: How can these guys -- and then we go back to products. We understand that there is a percentage out there -- and I think during the Intergy ICT hearings that it was like $30 million for every percentage we lopped off of this 20 that was out there that was savings. And then again for the last three years I've heard of a product differential and the inability to ramp and ramp down.

If you don't give these guys some kind of transparency signals how can you get them to come into the market anyway? And if there's nobody in the market then it doesn't matter; you know, if we don't have the market we don't have -- if we don't have the players we don't have the bidders in. And I can see where they would be frustrated as I would be frustrated if I keep trying to sell something and I keep getting turned down but I don't know why.

And we now we've got 30 percent.

And, Mr. Henry, I don't know how much purchased power Duke uses; I don't think you said in your presentation. But how much?

MR. SCOTT HENRY: Five to ten.

COMMISSIONER CALLAHAN: Five or ten.

But anyway, so I mean we've got some opportunity for sales that we're not taking advantage of. And I think you may have some frustration on the part of the merchants who are saying, you know, why even both. Why bother; why be it.

And I think if you're looking for -- trying to get, you know, your benefits of your economic dispatch you've got to have them bid. You've got to have the players. If you don't then you're going to be stuck with just the cost of production.

MR. MONROE: Right. And that's why I would agree with more transparent information. Part of it is transparency -- some of the -- you have to go through the reasons that Mr. Hurstell talked about, the limitations that they have to realize those additional capabilities. And these guys can go through but. But I think that the structure itself of the weekly procurement process isn't going to give them a lot of flexibility in the way that they bid.

So you have to go to other structures where they can actually give more flexible bids.

COMMISSIONER CALLAHAN: And then the other thing that I think that Mr. Priest and Mr. Beam have brought up great points of is what about those guys that are stuck in the middle.

You know, 55 percent of the state of Mississippi is not served by Entergy or Southern County but it's served by the munis and the co-ops. And they're out there held captive and, you know, while Duke and Entergy and Southern may be doing a good job of economic dispatch for their customers on their system, what about the transmission-dependent customers that are kind of stuck out there in the middle and how can we bring the benefits of economic dispatch to those customers who, in my state, is a majority.

And that's something that we face and struggle and wrestle with.

MR. MONROE: Yeah. I agree. That's why we're going to the Entergy imbalance market at least first. And I would anticipate that parties when they see the energy imbalance market are going to look at that and say, 'Well, we could make better decisions day ahead if we had a day ahead market too, or a day ahead unit commitment, at least.' And so the parties as they see the efficiencies gained in each of those values, whether you start with the weekly procurement process and go down to real time or whether you start at real time and go back up to a weekly procurement process.

I think providing that information about what's happening in the market will provide everybody a better way to compete within that market and reduce cost, as PJM has found.

MR. SAATHOFF: I'd like to just saying something from ERCOT's perspective. And I'm sorry Commissioner Parsley's not here; she could probably say it better than I can.

But one of the major considerations for the PUC to decide to go to the nodal market was price transparency and also the day ahead market. You know, right now we do have transparent prices, but the market has made arguments that PUC accepted that that's not granular enough to really foster competition.

And I think Carl made a good point that, really, if you have a competitive market that's when your really price transparency. And I think that's where ERCOT is heading.

MR. MONROE: To me it's kind of a chicken and -- price transparency and competition are kind of a chicken and an egg. You need, you know, to have competition you need price transparency. But in order to have price transparency you really need to have competition.

MR. PRIEST: It seems to me, though, that if you no go along paying 'x' that somebody over here or over here is not going to call me up and say 'I'm going to sell it to you for one dollar more than 'x.'' They'll call and say, 'I'll sell it to you for less than 'x.' It seems to me, if you know the price it's going to come down.

COMMISSIONER CALLAHAN: If you want it set in the market.

COMMISSIONER ERVIN: And, Mr. Chairman, I guess that was -- this may have been something that Mr. Hurstell said that I just didn't hear.

And if this requires you to repeat something you've already said, you know, chalk it up to my deafness, I guess.

I heard your argument with respect to objecting to posting your price, the prices that you purchased at. If you had an arrangement where everybody that was buying in some area -- and let's not worry too much about defining what that is -- so that it's not just your prices but everybody within whatever area we're talking about's prices, does that bother you as much?

MR. HURSTELL: No. As a matter of fact we have -- you can look every day and see into Entergy price --

COMMISSIONER ERVIN: Right.

MR. HURSTELL: -- onpeak and offpeak column. We don't provide information to that, but they get it from the sellers.

We can't stop the sellers from releasing information. We've said all along, if everybody wants to put out there what they're bidding, fine. Go ahead. Just don't ask us to do it.

We get bids every day. We get bids every month. And there is a dichotomy between those bids. And the market generally knows.

For example, we've just issued a monthly RFP for December. And we called an IPP to confirm why didn't they bid and they said, well, the guy told us. He said, well, you know, you're going to get heat rates of 6500 bid, and we just can't compete with that. And sure enough, the best bid we got was around a 6500 heat rate.

So I don't buy that they don't know what the market is. I really don't. Because we deal with them all the time. They're all generally in the same ballpark. So that's why I'm not believing there's this great benefit out there to us releasing our a real-time basis what we're paying for power. Because generally speaking, if they want to sell us more power they know what they have to do.

COMMISSIONER CALLAHAN: So you believe that the market's got an underground --

(Laughter.)

COMMISSIONER CALLAHAN: It's out there. It may not be posted but everybody's playing the market.

MR. HURSTELL: Remember that Henry the Second made the comment about, you know, he doesn't know really what his originating folks do. And I'm no expert at it either. But our guys talk to each other.

People are in this every day. The hourly people are doing this every hour. It's hard for me to believe that somebody who is devoting their life to competing in a market every hour or every day doesn't know what's going on in that market.

MR. BEAM: If I could add.

I think I can agree with John's comments as far as long term power supply and everybody knows what a new generator's heat rate is going to be and what gas costs are. And I think in a competitive market he's right. I think the traders do this on a daily basis; they know what the market price is.

But I think, at least in our area, there is not a competitive market. There are not a lot of players. And we've seen price quotes for the same product in the same hour of $150 from one supplier and $300 from another supplier. I'm sure that if there were competitors out there who saw that disparity they'd be offering a lower price to beat out the guy at $300.

So I think clearly price transparency would be a beneficial thing.

MR. HURSTELL: The other factor to consider, though, is if you're going to release all the prices and transmission calls us and says because of a transmission problem you've got to go buy from this IPP, you have to buy from him. And we're buying $60 power generally in the marketplace and all of a sudden we report that we paid $80 because we had to buy from that IPP and that's the price that that IPP set. Now what's going to happen. We just reported that we bought $80 power. All those people who were selling us power at $60, what are they going to want to do.

COMMISSIONER CALLAHAN: Probably be to send him up.

(Laughter.)

MR. HURSTELL: Exactly. It's going to go up.

COMMISSIONER CALLAHAN: But at that point you dispatch your own generation.

MR. HURSTELL: Well, exactly. But then maybe our generation was $75. So now we're paying 75 instead of 60.

It's not -- Electricity is not this homogeneous product that is interchangeable. Its location matters --

CHAIRMAN KELLIHER: But you just said a moment ago everyone knows what the price is. So they know that you paid 80.

MR. HURSTELL: Well, no. That's not the -- When we have to buy from an IPP because of transmission problems or because of reliability must-run, that's really not the market. The market is still going on between buyers who are free to buy and sell. So we don't -- I wouldn't call that $80 transaction a market transaction; that's a reliability must-run transaction.

CHAIRMAN KELLIHER: Okay.

MR. HURSTELL: And unless you're going to start differentiating between all the different types of purchases then I might buy from SUEZ because they've offered me 100 megawatts but they'll allow me to move it up to 200 megawatts with an hour's notice. So I might be willing to pay more for that. Are you going to classify that energy differently than when I buy from Calpine where I just buy 100 megawatts.

It's hard to say that there is this one clearly defined product that everybody's going to post their prices for. It's just not that simple.

CHAIRMAN KELLIHER: How does it work at the other hubs? How does it work at Palo Verde or Mid-Columbia?

MR. HURSTELL: I have the benefit of only have to work --

CHAIRMAN KELLIHER: Okay.

MR. HURSTELL: And I apologize.

CHAIRMAN KELLIHER: The thing I don't understand is why some trading hubs are excellent and reliable and liquid and others are not. I personally don't know and I'm going to have to get an education on that.

MR. SCOTT HENRY: Chairman Kelliher, may I make just one comment and one observation about price transparency. This may be a practical observation. But maybe as the first utility has been -- had its market based rate of authority revoked in the southeast, I'll just make the point that to the extent that we're a counter-party it will be a cost-based bid that we would be posting.

And again I will re-emphasize that to the extent that we have to post our costs, I think our consumers, our retail ratepayers end up being harmed because currently we do not have the ability to sell at market based rates for sales inside our control area.

So if there is an effort to have transparent -- greater transparency, price transparency -- we've talked a lot about transparency. I think there's transparency in transmission operation and then there's transparency in price. And we sometimes use those interchangeably.

COMMISSIONER ERVIN: Which is one of the reasons I asked for a definition of transparency early on.

MR. SCOTT HENRY: But if we're looking at price transparency I think the state of affairs in the southeast is somewhat problematic or else you're going to end up having to post -- essentially vertically integrated utilities posting potentially their cost or a cost-based rate or a cost-based bid.

COMMISSIONER CALLAHAN: Do you understand the frustration --

MR. SCOTT HENRY: Oh, I understand, sure. Sure. I certainly understand that.

COMMISSIONER CALLAHAN: We can agree on that, right?

MR. SCOTT HENRY: I understand the frustration.

COMMISSIONER CALLAHAN: And again, going back to what we said when we started this -- and this is kind of a fact-finding.

MR. SCOTT HENRY: Yes. I understand.

COMMISSIONER CALLAHAN: We're try to figure it out because if we are leaving money on the table because we're not dispatching an economic plant then that's hurting everybody. That's hurting the consumers, hurting your customers, my constituents. And that's what we're trying to see. How can we squeeze the most efficiency out of the process.

MR. SCOTT HENRY: I think there's one solution that has really not even been talked about today. And I've been trying to get a word in edgewise to maybe offer another thought.

I think Mr. Beam is accurate that they do perform economic dispatch. And I think Duke performs economic dispatch. I think most all of us do.

The vertically integrated utility -- Let me just -- Duke is I think quite proud of the portfolio of generation assets that it has. We've been running this system for years. We've designed and it's been developed in a manner to be flexible and to meet that instantaneous requirement that a load serving entity needs to do.

As the industry has been deregulated over time -- and even in FERC Order 888 the Commission found that there are certain generation services that were needed in order to accommodate transmission service. And those were called ancillary services. So in order not to have to do the minute by minute, second by second following of load and generation the FERC required transmission-owning utilities to make available ancillary services to transmission customers so that they could avoid -- or so that they had the ability to go out and procure in the market and get generation resources to meet their obligations and that they would not be constrained on the transmission reliability issues.

Well, back then when that happened it was much more difficult I think than it is today for load serving entities to take on that reliability obligation. NARUC has gone through a very extensive process of unbundling the control area. That's why we now have -- technically we don't have control areas now; we've got balancing authorities as it relates to the balance of real power supply and load.

So certainly if there's some obstacles -- and this has sort of manifested itself today in the discussion around the imbalance -- energy imbalance market and having energy imbalance markets. If that's where the issue is then certainly there's an option for load serving entities to become balancing authorities and develop a portfolio, a flexible portfolio of generation assets to meet the same obligations that we have as a vertically integrated utility that's done it for a number of years.

So certainly there is opportunity out there beyond just creating new markets and things like that for some of these problems to be resolved.

Now I'll be the first to admit going out and becoming a balancing authority is not going to address the issue of constrained transmission. And that has clearly been identified here as one of the problems. But there are -- if you start breaking down the issues that we talked about today, there are some alternative solutions out there.

Thank you.

MR. O'CONNELL: Mr. Chairman, if I may.

I'm glad that one of my fellow panelists brought up the issue of the ancillary services in Order 888. This is an issue that Williams faces in trying to serve its customers in Georgia. There are some significant issues that we believe need to be discussed with respect to that.

Rather than delving into that I would just ask that the panel look at some of the responses to the NOI on Order 888. I think there will be many merchants out there that offer some opportunities for improvement in that particular area.

MR. BEAM: If I could respond to Mr. Henry's idea of load serving entities forming their own balancing authorities, that's certainly something that we've considered. I think that it's something that would be somewhat complex and expensive for us to do.

But that aside, I don't think it would solve the problems that I brought out here today about the fact that we as a load serving entity with contracts that must be scheduled across transmission interfaces face a number of impediments that make it difficult for us to follow our load and to balance our load in a way that would be necessary as a balancing authority.

So it's not as simple a process as just forming a balancing authority and the problems go away.

CHAIRMAN KELLIHER: Any other comments?

Jimmy.

COMMISSIONER ERVIN: Maybe just to finish up on a positive note, this was something that David alluded to in his comments and something that my colleague, Commissioner Parr, who has diligently leaned against the back wall for most of the meeting has pointed out.

(Laughter.)

COMMISSIONER ERVIN: But I think, Mr. Chairman, that one of the things that we probably -- or that I hope we have started this afternoon is at least some process of greater communication among some of these interests.

Mr. Beam in his statement alluded to a process that Jim, and to a lesser extent I helped foment in North Carolina, which was to try to get the transmission-dependent LSEs to communicate really better with the IOUs. And while I think a lot of folks were somewhat dubious initially that anything productive would come out of that, and while that process still has a way to go, I think that -- and all they decided to address up front was planning because I think that was the TDU's biggest concern -- I do think that that process, whether or not it produces any great massive change in transmission architecture in North Carolina, has at least served to get some folks who didn't communicate as perhaps well as they should have early on to do a better job of that.

And my hope is at least today that this process can be a way to identify some issues that some of these folks ought to talk about more than perhaps they have. And so I hope if we haven't done anything else we've at least provided a forum in which people can do that.

And I'll be quiet at this point. But I do think that there are a lot of complexities in these issue that's way beyond the ability of us esquires and J.D.s to try to be prescriptive about. There ought to be ways that some of these issues can be addressed -- I think there at least some model in North Carolina for at least starting to do so. And I would commend that kind of approach to my colleagues and to the folks in the room in case you're interested.

MR. BEAM: If I could respond?

I would say that I was one of those that was very dubious about that process and what it would produce. But I'd have to agree with you that just the act of talking, sitting down at the table with the other LSEs in North

Carolina has been very productive. I think a lot of the barriers that we had seen before I think have been melted away to a great extent. So I think we've already seen some benefits just in terms of communication.

MR. SCOTT HENRY: I agree.

CHAIRMAN KELLIHER: Any other comments?

MR. PRIEST: As Dorothy said to Toto in The Wizard of Oz, "We're not in Kansas any more."

(Laughter.)

CHAIRMAN KELLIHER: Any offense to that, Chairman Moline?

(Laughter.)

CHAIRMAN KELLIHER: No?

Well, why don't we -- This has been very interesting, I think. It's been educational. But it's been enough, too.

(Laughter.)

CHAIRMAN KELLIHER: So why don't we take a 15-minute break here. And Joint Board members, let's come back and talk about next steps and product. Okay?

Thank you very much. I thank all the Panelists for their participation. Thank you.

(Recess.)

CHAIRMAN KELLIHER: At this point I wanted to have really a discussion among the Joint Board members about product and next steps. And I think we, you know, we spent a lot of time today talking about how economic dispatch is done in the south and we talked about how it's done different ways, system by system, in ERCOT it's done on a regional basis, SPP has got its proposal pending. So there is a little bit of variety in the south in how economic dispatch is done.

And we've talked a little bit about improvements, possible improvements to how economic dispatch is done in the south. And it's really that second area that seems to be the one we need to focus some attention on in the future.

So it's really that area of improvements, possible improvements that I think we need to spend some time on and discuss at a possible future meeting.

So as a threshold question, should we have another Joint Board meeting. And if so, should we try to do it at the NARUC winter meeting in D.C. That's something I'd like to get a sense from the Joint Board members.

What's the product? We are -- this is a regional Joint Board. The regional Joint Boards are supposed to make recommendations to the Commission. The Commission in turn is supposed to report on Congress, including possible recommendations. So there's a product that we have to give to the Commission. And the Commission has laid out a deadline or a target of May 2nd, I think, May 2nd for all the Joint Boards to deliver a product to the Commission for its consideration. The Commission in turn has an August 8th deadline to report to Congress.

So, you know, one possible product is simply to summarize how economic dispatch is done in the south and do nothing else, summarize the status quo. But do we want to do more than that.

Do we want to identify possible changes in how economic dispatch is done, regulatory changes, statutory changes. That one still seems to be an open question. There has been discussion today about possible changes, and we have explored that. Should we explore that some more? I think it would help.

We have a comment period open through December 5th for this Joint Board meeting. And I think it would help if we got comments from stakeholders addressing the issue of improvements, what changes or improvements could be made to economic dispatch, and for people to particularly highlight if there's a need for regulatory or statutory change to achieve that change or improvement that it would help to make that plain.

But, you know, the record is still open. The DOE Report will become part of it.

The DOE Report in turn is a survey of stakeholders, including in the south. I read some of the submissions, but I think -- I'm just -- I can't recall to what extent DOE asked or people volunteered suggested regulatory or statutory changes in their comments.

But the question is procedural: How do we go forward? How do we wrestle with the question of improvements? How do we reach some resolution?

The very least of our product is a description of how economic dispatch is done in the south. But I think we should decide to either make further -- to identify possible improvements or decide not to identify possible improvements because we don't think there are any or we can't agreement on what they might be.

Sandy.

COMMISSIONER HOCHSTETTER: My personal observation is that there seems to be a lot of overlap between the subject area of economic dispatch and the issues of transmission congestion, transmission planning and expansion, Order 888 operation and that sort of thing. And also the operation of markets -- not necessarily organized markets but, you know, how you can have a more robust wholesale market even in the -- quote, unquote -- "non-organized" areas and whether you could have that in an ICT structure or just through some kind of a hub.

So I think that in terms of recommended improvements I wouldn't necessarily categorize those in the economic dispatch definitional area in terms of how economic dispatch itself operates but rather in the broader sense of how can we improve the delivery of more economic generation to customers by looking at it more broadly in terms of how transmission system is planned and expanded and how congestion is evaluated and how we can get the independence and transparency in there.

And a lot of those sorts of issues have been addressed in ICT dockets. And I think some of those issues will be addressed in the Order 888 NOI that you have out there also. So it may be that we'll see more and more convergence of these issues in these other pending FERC dockets, and that may give us more information in terms of the timing of next steps as to how those other dockets proceed.

CHAIRMAN KELLIHER: I agree with that.

But this -- I mean the Joint Board, according t Congress, its sole authority -- and that's the word that Congress used -- the sole authority of each Joint Board is to consider issues relevant to economic dispatch, not a broader question on how to make markets more competitive. You know, economic dispatch is arguably a subset of that broader universe.

But, you know, Congress did say, "The sole authority of each Joint Board is to consider issues relevant to security constrained economic dispatch and to make recommendations on that subject."

COMMISSIONER HOCHSTETTER: Wasn't there something in that definition, though, about transmission within the statutory language?

CHAIRMAN KELLIHER: Well, the security constrained I think infers at least in part transmission constraints, right. But, yeah, if one of the limitations on economic dispatch is transmission limitations, to what extent is that something we can address as an economic dispatch Joint Board. I mean we just can't get too far afield, though.

COMMISSIONER ERVIN: It seems to me -- and I'm a whole lot better on process than I am on substance, unfortunately. But I really have two comments after listening to all of this.

First of all, particularly if we still have a comment period open I don't see how we avoid having a second meeting because if we try to reach some kind of a conclusion here we're going to be telling people give us comments but we're not going to be paying any attention to them because we have already made up our mind. So as a practical matter I don't see any way to avoid having second meeting.

I also think having a second meeting would be helpful. We've heard a lot of information. The south is a big area. And we've listened to a lot of discussion about different things in different parts of the region that may not -- may or may not be applicable to other parts of it. And there's a fair amount of material that we probably need to digest just in terms of sitting here.

What I would suggest that we do is certainly try to have a second meeting. Trying to have it around the NARUC meeting makes sense. I will tell you, as you and I have discussed previously, there are some scheduling issues revolving around that because of the electricity delivery forum that NARUC and DOE and some others are working on means we can't do it after NARUC's over but we perhaps could do it on the Saturday or Sunday before then.

In terms of what we did, it seems to me that -- I mean, I agree with you. I was thinking when Sandy was saying what she said earlier that we need to stick with the definition that Congress has given us in terms of what is our charge. But having said that, I think it would be helpful if some subset of us could at least focus on what are the potential issues in terms of improvements that need to be addressed. We could have a really wide ranging diffuse discussion about potential improvements and we'd probably wind up really having an interesting talk and not getting anywhere.

And so it seems to me that there ought to be some way for us, once all the comments are in, once we've had a chance to consider the stakeholder input that we've received this afternoon, to at least identify possible improvements that we could then discuss in a more focused manner rather than trying to just open the floor up and say, hey, somebody want to talk about improvement.

COMMISSIONER CALLAHAN: Well, you know, going back to kind of the process, what if -- if the comments are due by December 5th could we, by January 31st have kind of a draft report that we could then put out and then the meeting in February would be to discuss and take comments on our draft report. Would that give us enough time to do that?

CHAIRMAN KELLIHER: Well, we can either have a draft report or we could have the improvements that have been proposed in those comments. We could have some kind of paper that could help structure a discussion at a future meeting that would help us focus on the issues.

And there was a question about the transcript. The transcript of this meeting will be available on our website for about a week o so, in seven calendar days for free.

Any other comments from my colleagues?

(No response.)

CHAIRMAN KELLIHER: So I think that's a plan. We'll get comments by the 5th. FERC Staff will recapitulate them, summarize them in some form, and we will have some product out to the Joint Board members by the end of January to help guide the next meeting that may be in Washington, which is south of the Mason-Dixon line as well.

(Laughter.)

CHAIRMAN KELLIHER: At around the time of the NARUC meeting, or it might actually be somewhere in the real south of the NARUC meeting does work.

Any other comments?

(No response.)

Kevin, do you have anything you'd like to say?

MR. KOLEVAR: No.

CHAIRMAN KELLIHER: No?

MR. KOLEVAR: It was very interesting.

CHAIRMAN KELLIHER: Good. Good.

Well, I just want to -- I want to thank my colleagues on the Joint Board. I want to thank NARUC for allowing us to crash their annual meeting.

I want to thank the presenters and I want to thank the FERC Staff for putting this together. As I said, this is new for us. And it has been enjoyable.

Thank you very much. And enjoy the rest of the annual meeting.

(Whereupon, at 4:30 p.m., the hearing in the above-entitled matter was adjourned.)