BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 020233-EI

In the Matter of

REVIEW OF GRIDFLORIDA
REGIONAL TRANSMISSION
ORGANIZATION (RTO) PROPOSAL
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VOLUME 2

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PROCEEDINGS:	WORKSHOP
BEFORE:	CHAIRMAN LILA A. JABER COMMISSIONER J. TERRY DEASON COMMISSIONER BRAULIO L. BAEZ COMMISSIONER MICHAEL A. PALECKI COMMISSIONER RUDOLPH "RUDY" BRADLEY
DATE:	Wednesday, May 29, 2002
TIME:	Commenced at 9:30 a.m. Concluded at 4:46 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR TRICIA DeMARTE Official Commission Reporters FPSC Division of Commission Clerk and Administrative Services (850) 413-6732
IN ATTENDANCE:	(As heretofore noted.)

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

CHAIRMAN JABER: We're going to go ahead and get started. Commissioner Bradley will join us as soon as he can. And I understand, FMPA, you want to finish up on a last point.

MR. BRYANT: Yes, ma'am. If I might have Mr. Linxwiler more fully respond to the question that you asked, Madam Chairman, about the way the TDU adder works, if Mr. Linxwiler could respond in a little bit more detail to that.

CHAIRMAN JABER: Mr. Linxwiler.

MR. LINXWILER: Thank you. I apologize. I guess I've been working on this stuff way too long because I take too much for granted and sometimes don't explain some of the key parts of it like I should.

The TDU adder that I referred to is one of essentially three components of costs that are proposed to be included in the zonal rates and charged to all of the retail ratepayers of the investor-owned utilities.

We believe these three charges, the TDU adder being one, is one of the -- these are really key components of the plan, short of, and this is really in lieu of, you know, the alternative that I mentioned that we preferred where all ratepayers were under the same transmission tariff. Short of that, we think these three charges are important.

Briefly, you have the grid management charge, which are the administrative costs, more or less, of Grid, of GridFlorida, the RTO, providing grid management services to the applicants as well as other transmission users.

Second, you have the charge for new transmission facilities that would be rolled in and shared on a traditional roll-in basis by all transmission, all users of GridFlorida.

The delineation between existing facilities and new facilities involves the issue that I mentioned briefly, and I believe Mr. Miller mentioned it, the demarcation date, the line that's drawn as distinguishing between old and new facilities in the new filing that the applicants have -- in their compliance filing the applicants have attempted to advance that date and we believe it should stay as originally proposed to FERC.

Then the third element is this TDU adder, and this would be the mechanism by which it would be an additional charge and it would recover the revenue requirements of TDU facilities, transmission dependent utility facilities such as the facilities of many of FMPA's members, many of the cooperatives, and I described those facilities.

That TDU adder mechanism is what we certainly support. Now what exactly goes through that in the facilities that are, the cost of which are included in that TDU adder, that is a matter of some disagreement. And if you've seen our pleadings, you've seen we have, we have some disagreements with the applicants on that. We're making our case at the FERC and ultimately I believe the FERC will resolve that issue.

We believe that TDU facilities should come in at day one, but that is a difference. And we have suggested -- throughout the collaborative process we talked about a number of different phase-in mechanisms for the TDU costs. That hasn't been decided yet. FERC will decide that. But what we certainly support is the notion of this TDU adder that whatever facilities do come in and whatever phase-in is ultimately determined, we believe that's appropriate, an appropriate mechanism to flow those costs through to all users of the transmission system. And I appreciate the opportunity to --

COMMISSIONER DEASON: Let me ask a follow-up question. You indicated that the demarcation date is important as it relates to defining new transmission facilities. Is that because the new transmission facilities will immediately be included in rates while the TDU adder will be phased in, or what's the relevance there?

MR. LINXWILER: That's, I think, the key point. As to -- I think the particular facilities that are up for grabs, if you will, or that would be captured by that net, as Mr. Miller referred to it, are facilities that really are on the bulk power grid as to which there are, I think there's little question that they really support the grid and are very key bulk power facilities.

Seminole has the particular issue with the Calpine resource, FMPA has the, has the concern with respect to the transmission coming out of Cane Island and interconnecting with Florida Power Corporation and all of these other utilities I mentioned in Central Florida and really beefing up the grid in the fast-growing Central Florida area.

So it really has to do, I think, with those very key facilities. Some of our other cities have been adding small amounts of transmission recently and so there's some question there, but I think that can be sorted out.

The big problem is with the major additions that FMPA has been making. And at one point we were assured that those facilities would be considered new facilities and we wouldn't have to jump through a whole lot of hoops to demonstrate their contribution to the grid. We think we can, but it's certainly an administrative burden and a certain amount of regulatory risk involved there. To move that time line, that demarcation line out just causes another big controversy that I think has to be resolved.

COMMISSIONER DEASON: Thank you.

MR. LINXWILER: Thank you. Thank you for your additional time.

CHAIRMAN JABER: Let me ask you on the procedural question, you said it's a matter -- there are disagreements pending at FERC. Did you file, did you file the notion of the TDU adder as part of the GridFlorida original filing or is it a separate proceeding?

MR. LINXWILER: The TDU adder is a slightly new mechanism. The original GridFlorida proposal that was filed at FERC included all of the investor-owned utilities taking service from GridFlorida under, for all of their retail load under the standard GridFlorida tariff.

And in that tariff there were similar mechanisms, but it would be one rate. Well, there would be zonal rates, but there were similar mechanisms. The TDU adder as a particular mechanism arises, in my view, because, as a separate charge because now the applicants have proposed to keep the retail load out from under the GridFlorida tariff essentially.

CHAIRMAN JABER: Okay. I think I'm still not understanding. So the TDU adder is something you raised as an alternative because of the modified proposal, but you're not asking that we act upon it because it's your position we don't have jurisdiction to rule on the notion of a TDU adder?

MR. LINXWILER: No, not at all. And on the jurisdictional question, let me --

COMMISSIONER JABER: Well, then you've got me completely confused.

MR. LINXWILER: I don't want to play, I don't want to play lawyer, and perhaps Ms. Bogorad will or Mr. Bryant would want to respond to that, but I think the TDU adder comes about as a different mechanism that I think is, is properly considered by this Commission.

Perhaps -- as I understand it, the costs that the TDU adder would recover, the specific costs and the timing of recovery of those costs is a matter that FERC will consider. And that issue -- the issue is on rehearing at the FERC now.

CHAIRMAN JABER: Commissioners, am I the only one that --

MR. LINXWILER: And the TDU adder is the applicants' proposal, I want to make that clear, and we support that portion of their -- the support I expressed earlier is support for their proposal for the TDU adder. We may disagree with them on what exactly goes into it, but we support the mechanism as they've proposed it to you.

CHAIRMAN JABER: I see. Okay. But there is no disagreement with respect to the jurisdiction of this agency to, to rule on that pricing structure. Mr. Bryant, help.

MR. BRYANT: Well, we believe that the jurisdiction lies solely with FERC on that.

CHAIRMAN JABER: Okay. Am I the only one hearing the two of you talk out of both sides of your mouths? Am I the only one? Because that's okay, you can tell me I've completely misunderstood.

MR. BRYANT: The pricing is what you indicated, Commissioner, and pricing at wholesale is exclusively the jurisdiction of FERC. And only that affects us is at wholesale. To retail it's your jurisdiction which involves investor-owned facilities, which does not involve us.

CHAIRMAN JABER: You don't consider the TDU adder part of the pricing structure? That's the way I've been looking at it.

MR. BRYANT: Well, you have --

MR. LINXWILER: Not in the wholesale.

MR. BRYANT: Not in the wholesale. You've got the retail part of it and you've got the wholesale part of it. You have the retail, FERC has the wholesale. Where the two separate becomes difficult under the proposal.

CHAIRMAN JABER: So the TDU adder is part of the pricing structure for retail recovery?

MR. BRYANT: The mechanism. The mechanism. The formula. The dollars of the TDU facilities that we say are appropriate, they disagree with. But that disagreement is at FERC because that's where the jurisdiction is, not at this Commission.

CHAIRMAN JABER: Okay.

MR. BRYANT: I hope I made that clear in my very limited ability.

CHAIRMAN JABER: I'll keep thinking about it and I'll let you know.

COMMISSIONER DEASON: What about, whether his ability is limited or --

CHAIRMAN JABER: I -- we were going to leave it purposefully vague.

All right. JEA is up next.

MR. JOHN: Is that going to be up before --

CHAIRMAN JABER: Is it? Yes. Florida Municipal Group. You're right. No. I just skipped over them.

Good afternoon. My name is Doug John on behalf of the Florida Municipal Group. I'm from the law firm of John & Hengerer up in Washington, and in that capacity I've represented these four members for quite some time about gas matters and more recently on power issues before the FERC.

The Florida Municipal Group is really a call sign for an ad hoc collection of four cities: The City of Tallahassee, the City of Gainesville doing business as Gainesville Regional Utilities, the City of Lakeland doing business as Lakeland Electric, and Kissimmee Utilities Authority.

These four have banded together here and before the FERC in connection with electric restructuring to try and come up with common views and try to look after their interests there as well as here.

Now these four are unusual, I guess, relative to the other people you've heard from this morning in the following respects: Each one is pretty much an OASIS, each one has generation facilities, limited transmission and a significant distribution system in a footprint that is all contained. Whereas, the IOUs are far-flung across the state and, whereas, the TDUs, of course, have load centers and generation but are separated by somebody else's transmission, our folks tend to do it all within one integrated system and only provisionally rely upon the outside utilities for remote access to remote generation or for selling off surplus power from time to time. And that gives us a different kind of perspective than these other folks.

We, to be honest with you, we are in a defensive mode. We have been since the very beginning of the, the Order 2000 implementation process at FERC and we certainly are before you folks. We think maybe you share that sense as well, given the juggernaut that seems to be descending on us now from Washington.

And so our objective is not so much as to exploit opportunities as it is to protect what we've worked hard to develop over the years and to try to take as little risk as possible of losing the benefits both in terms of reliability and economics that we have in place.

The City of Tallahassee, one of our four members, is a little different than the rest because, whereas, the other three are embedded securely within the Florida Reliability

Council, Tallahassee sits at the top of that reliability system and alongside the southern system. And that gives us a concern about what are called seams issues that, along with JEA, we think are unique to the two of us.

You're fully aware, I know, that Tallahassee, to protect its long-term best interest, has been active not only here and in the GridFlorida proceedings at FERC, but also has been active in the SETrans experiment that's been going on now for several months.

SETrans is a form of ISO, really an ISA that's being developed north of the Florida border through the Carolinas and in Georgia, extends all the way down into Texas through Louisiana. And later in the summer, in the middle of June there will be a set of definitive documents being filed with the FERC by the SETran sponsors that will be requesting reaction from the FERC for the first time on whether they're heading down the right road in terms of governnance and the various protocols they're developing up there.

From time to time in the next few minutes I may refer to what SETrans is doing. One of Tallahassee's concerns, and I think a concern for all of us ought to be consistency between adjacent RTOs. And since we have the benefit of a pretty familiar activity level with SETrans, I may make some observations about areas where we see divergence and would prefer not to see that, if we can help it.

Everything I'll tell you about SETrans is public. They have a web page that's been set up and all the documents that are still evolving are posted on that web page, as I said, looking toward a filing date of later in June with the FERC.

Now the reasons we're defensive, just to be more specific, are we are concerned about losing our local control, the ability to build what we think we need to build in the footprint and to operate to serve our own local interests. We're concerned about higher costs. We're particularly concerned about the transco concept because we thought that would have a natural tendency to inflate costs and we'd all pay it one day. We're concerned about reduced reliability. And more recently we're concerned about the competitive forces that are not very well understood in the marketplace, and we've heard those mentioned by previous speakers today, things that, again, it's not so much a matter of fearing any one force, but the unknown.

But we do feel that RTOs are inevitable. So rather than just kind of shouting out the dark, our objective is to try and shape this as best we can with the intention of being a participant, again, if we can see clear to do that.

We do feel there are some very positive aspects to RTOs, including GridFlorida, particularly with respect to centralized planning. That's an area that, you know, we feel perhaps can be improved on, and we like a lot of what we see, frankly, in the proposal from GridFlorida in terms of how that will go forward.

In past -- I'm going to get to the 14 questions here which I know you want to hear our views on. Before I do that, I want to share with you just a few of our, of the things we've told the FERC and perhaps some of the points we've made to you folks in our comments so you understand on an issue-specific basis what we would like to see happen when the smoke is clear.

Number one, as municipal corporations, preserving our tax exempt status is critical. We think that the GridFlorida folks are sensitive to that. SETrans, which is very, much more heavily weighted toward muni and cooperative interests, we think is that way as well. And we believe FERC's policies are designed to make room for that sensitivity. But as we formulate positions and advocate this and that going along, that, of course, protecting that tax exempt status is something that we need to be mindful of.

We have another issue, and it's one that actually appears in your December 20 order as being resolved when it isn't, and that is the question of the 69 kV bright line test. The applicants here have seen fit to, for whatever reason, and they had their own reasons, to designate transmission facilities, control facilities as anything 69kV and above regardless of what it does if it's owned by a participating owner.

We, on the other hand, viewed the Commission's rules, the FERC's rules as not requiring that, but instead requiring a more functional approach. You know, if the facility fits a grid function, if it's important to the well-being of the State of Florida on a, you know, a transition, a transmission level basis, then we fully understand it needs to be committed. But to the extent we have localized loop facilities or radial lines that really perform no grid function, no discernible grid function that we can see, we think we should have the opportunity to demonstrate that those are localized. And notwithstanding what could be 69kV voltage rating or even a 115, that these are, in fact, local distribution facilities in their function and we ought to be permitted to keep them out, if we choose to. We do recognize that if we do that, we're not going to get any cost recovery on them from the grid rate. That'll all be a matter of our local distribution rates. But there are cities, Tallahassee, Lakeland, particularly, who have felt strongly that we shouldn't be railroaded into putting in a facility just because it has a certain voltage level and just because the IOUs are committed to doing that themselves.

The Commission, the FERC has never really spoken to that. It was part of the filing that was made by the company, the companies, but in its orders in March, the FERC really rowed by that. It was never really specifically addressed. It's on rehearing before the Commission. And bottom line here is there is no record supporting that that I believe has been embraced by any agency, and I would ask you folks just to be aware of that as we go along and perhaps to understand where we're coming from in choosing, if we can, to operate on a functional basis in deciding what goes in and not on a bright line basis.

We do appreciate the option that's available here to exclude retail load. It sounds like the IOUs are each going to embrace that for five years. And we -- some of our cities who will be looking at large cost shifts feel the same way about that.

We have some concern over the new facilities charge. It really is a lessened concern from what it was before, but the concern we have is that to the extent people have a responsibility to build facilities, they ought to build them. And if there is a -- we wouldn't want to see anybody motivated to delay building facilities in order to have them paid for by the entire system as part of that system facilities charge, when, in fact, it really ought to be built to deal with responsibilities now and become part of a zonal cost of service.

On congestion management, we have read your order. We have no problem with any of the four fixed decisions you've made, including the use of physical transmission rights for the foreseeable future. We understand that you view this as a transitional, each of these decisions really is transitional to keep your options open and we're, we abide by that.

Particularly in the case of Tallahassee, the way the PTRs are allocated will be critical. Tallahassee, along with Jacksonville, of course, has rights at that interface that are, that they're really unique to them because of the fact that they sit in the seam up there and they would need to ensure that they have access to the use of that tie on a basis which is consistent with what the reliance, the reliability or the reliance they've placed on it over the years.

We have some concern about an aspect of the filing dealing with eminent domain and the obligations of an incumbent utility to exercise its own eminent domain powers to build a facility for somebody else. In our judgment, if a merchant transmission line comes along, it really ought to be viewed as an entity qualified to obtain their own eminent domain rights, and only in extreme circumstances should we be forced to exercise ours on behalf of somebody else. I say that as much for political as other reasons.

In terms of the ICE, the install capacity requirement that is rather vaguely developed here in the pleading and has been from the beginning, our view is that is an area that's fraught with room for mischief. We tend to think that the historical approach of having this Commission and the FRCC together decide what is appropriate in terms of long-term reserve requirements is the right way to go for the foreseeable future. So we are suspicious, frankly, of an ICE or an ICAP requirement voluntarily being adopted down here.

I mentioned seams issues for Tallahassee in terms of access. There's a rate aspect to that, too. Tallahassee historically imports and exports across that tie. And to the extent adopting RTOs here and SETrans would create pancake rate risks, we are hoping that a reciprocity agreement will be established that will avoid those. And that's something not enough attention to, not enough attention has been given to yet.

The last point in my intro here is that, is this: If, when all is said and done, you know, we've decided what the designation of transmission facilities is, we have the planning protocol, the operational protocol in place, if at the end of the day for valid business reasons any of our cities elects not to volunteer to be a member of this, we don't want to be hit over the head with a two-by-four. You know, the objective here would not be to create a hopscotch pattern so we can extract monopoly rents from anybody. The objective would be to protect the interests I've talked about, which are looking toward our local retail consumers. And I would hate to have this Commission or the FERC, when all is said and done, authorize a penalty rate or a punitive rate to be attached to us if we want to use the, the RTO facilities to export and import power.

And so what we're volunteering to do is to enter into whatever form of reciprocity agreement would be appropriate, just like another RTO under these circumstances, for service through our system and through the adjacent system into us. And, there again, it's really a topic that would take several more minutes to discuss than I have, but I just for the moment will leave with you a commitment that if we objectively elect, at least for the moment, not to go in, we would hope that there is a form of reciprocity we can establish with the GridFlorida folks that would be fair to both parties.

Now in your December 20 order you, and the May 15th notice you've basically given us some assumptions and you've given us 14 questions. The assumptions, things not to be addressed but inevitably will have to be as part of standard market design at FERC are the get-what-you-bid approach in balancing energy, physical transmission rates, balanced schedules and, of course, the ISO structure. So we take those as givens for now. To the extent these are going to be important in the long-run, then it's going to be important to this Commission and to the rest of us to be active in this proceeding before FERC and to make known our view and perhaps with the objective of trying to get as much flexibility for regional variances as we can.

Now 14 issues. First one, appropriateness of the not-for-profit versus the for-profit ISO. We don't view this really as a significant difference either way because of the way things have evolved. We're very supportive of your decision to insist on an ISO for the reasons that you've given in the December 20 order. We think that is the right way to go. It removes a lot of the fear we had about GridFlorida in the form of a transco both in terms of bias and rate inflation.

SETrans is going down a not for -- I'm sorry -- a for-profit ISA route that's a little different on its face but not really fundamentally. What they're doing is they're basically opening up a request for proposals in which existing competent companies like National Grid, PJM and others have come forward and indicated an interest in becoming the independent system administrator, SETrans. So you take an existing corporation, an existing board that satisfies the independence requirement, code of conduct, creditworthiness, competence and so forth, and are willing to enter into an agreement that's being developed in which they commit to operate the system according to a certain set of values and standards.

Now in that case they are viewed as for-profit administrators because these are for-profit companies. But we're not talking about a for-profit in the traditional investor-owned utility sense of a rate base and a return on invested capital so much as we are, I think, a set of standards in the contract that establish the same kinds of performance incentives we're talking about for not-for-profit here. Now this hasn't been finalized, but I guess the bottom line is the fact that we may have a for-profit company acting as an independent system operator or administrator in an RTO doesn't necessarily mean that they're motivated to behave in ways other than they would be as a not-for-profit. What you do is incentivize them with performance incentives. Mike Naeve mentioned that they have somebody who is assisting them in developing a set of those, and the SETrans people are doing the same. So the FMG is not bothered particularly by one structure or another, provided the incentives are judicially adopted, I mean, are appropriately adopted.

Number two, flexibility of the RTO plan to change over time. In our judgment, the POMA, which is the contract that the owner is going to sign to go into the operation, should not be easily changeable. You know, if you're going to commit your control to somebody, you don't want through a simple complaint filing or a tariff filing to see it changed six months later. It ought to be difficult to change the POMA and something that's done either collectively by the signatories or upon a complaint filed with FERC under Section 206 of the Power Act.

The protocols are part of a tariff. Those, on the other hand, planning, operating, we'd like to see those protected as well. But as tariff provisions they're going to be more amenable to modification as time goes on and as things like the standard market design are improved. The munis will need some off ramps. I mentioned the concern about tax exempt status. I think a muni that decides to go in and finds that, for any number of reasons, the quality of service or for whatever reason, other reasons it's not working out ought to be able to withdraw and to do that without having to sell their first-born sons. And there is room in the GridFlorida filing to accommodate that. It's unclear what authorizations FERC would have to issue, but we can take those, cross those bridges when we come to them at FERC.

Application of the code of conduct to the GridFlorida board, the Board Selection Committee and the State Code Advisory Committee, we pretty much agree with what GridFlorida told you in the May 6th data response to this that the board itself clearly has to be, has to be exposed to the code of conduct that govern this operation; whereas, the committees are in an advisory, non-operational role, and we do not have a problem with GridFlorida's comment that the code of conduct really should be applicable, should not be applicable to them in that role.

Board meetings open to the public. Here again, we're willing to go with the GridFlorida approach. We think they have made good progress in the revised structure here to open their meetings to the public. We are amenable to having executive sessions held where confidential data is exchanged.

Performance incentives, we don't have an opinion as to what those should be. As I said a few minutes ago, we do believe there should be performance incentives, whether we're talking not-for-profit or profit, and clearly those shouldn't be designed to favor transmission over generation. But, once again, what, exactly how they should be structured is an open issue.

The role of this Commission, perhaps the most important issue of the day, I think, we are looking for your, your help here. And we think that you have a great deal of, the ability to have a great deal of influence in what happens in this state, even if it's the FERC that makes the calls.

The FERC is clearly soliciting state input. They recognize that the lines between, the jurisprudential lines between the FERC and the state commissions are not that well drawn and we're going to be making some new law if we have to fight battles over them. So to the extent we can collaboratively with regulatory kind of things come up with a solution that fits both, I think we should do all we can in this state to try and achieve that without bloodletting.

Now there are two forums open to us at the moment. One is the GridFlorida proceeding in RTO 1-67. The Commission has got that on hold right now waiting to see what happens down here. Their rehearing is pending, as I mentioned. And I would imagine that the IOU's plan is, once we're finished here, to make a filing with the FERC that accommodates the decisions that you've made and the recommendations you've given them hopefully as opposed to brinksmanship where they decide not to. And to the extent we can influence that filing and then support it at FERC, I think the state has an opportunity here to help shape where we're going.

I would encourage you, as others have, to be involved in the standard market design. If we have a need for regional variances here, we ought to make the FERC aware of that now and not in a petition that we file after they've adopted a standard set of rules for all of us.

Your facility siting authority clearly is going to be intact. And so notwithstanding the planning mechanisms that are going to be built here, ultimately before a generator can be sited or a transmission line built, it has to clear your front door.

Reliability. I've already mentioned that as far as we're concerned for the foreseeable future, rather than going to an ICAP or an ICE approach, we would think the traditional reserve requirement standards that you and the FRCC have used are appropriate, and we generally agree. I just compliment the people, the folks at FMPA. We think they've done a very good job in their comments of articulating the standards that would be appropriate there.

Demand site alternatives, which we deem to be really of two kinds, the ability of the industrial to perhaps ratchet back and perhaps the use of distributed generation, localized generation. We feel the RTO needs to take that into account and it should do nothing to discourage it. By the same token, particularly if these facilities are located on low voltage lines that are embedded in distribution areas, we would think that the PO, the participating owner, should be given quite a bit of autonomy to assist or to really oversee how the, that generation is fed into the system.

ATC, the role of the PO in determining, we agree with GridFlorida here that it's appropriate to have the participating owner provide a statement of its available transmission capacity in the first instance, recognizing that the ISO will have to verify that and be responsible for posting it on the OASIS.

Use of PTRs. Okay for now, as I said. Physical transmission rights for at least a five-year period. FERC may override us on this, but we do support where you are at the moment in your thinking based on the December 20 order.

We do want to have compatibility with the Southeast Reliability Council on this when we're finished, and we're working to try and achieve that.

How to determine flowgates. Well, again, we're not, not disappointed in the way this is evolving so far in

GridFlorida. We think they have to be based on historical use. Tallahassee has built, financed a good part of that intertie that I explained up in the north, and certainly in any allocation of rights across that flowgate we would assume to be, our needs would be met.

We do have one small issue here, and I think it may be one that's been picked up before, and that is with respect to the non-flowgate congestion that may occur.

The way the proposal is now laid out, all of the consumers in the, on the down side, if you will, of that congestion would wind up paying the cost of relieving that congestion. In our view that is unfair, particularly insofar as we didn't cause it. And instead that cost either ought to be socialized or ought to be allocated to the specific users of that capacity that are not historically, not historical users.

Pricing of ancillary services, Number 11, no strong opinion about this. Two observations. We need to have the right to self-supply, which I think we do have under the proposal. And as everybody else, I believe, has said, until a showing of no market power has been made by the IOUs, we would be opposed to permitting the investor-owned facilities to sell ancillary services on a market based, market basis.

Number 12, proposed cost recovery and mechanisms. I mentioned our concern about the new facilities, that we would want to be sure there's no gaming here of moving a facility, delaying a facility to basically build the system for it when, in fact, it ought to be the responsibility of the utility in whose zone it will fall to build.

Number 13, TDU costs and zonal rates. We have no -- this really is someone else's fight and we certainly don't want to influence it either way.

I will say one thing. It's interesting to hear the investor-owned utilities argue that TDUs, in order to commit their facilities to the cost of service of the IOU zones, have to prove integration. They seem to have to prove a functional connection to basically get their facility committed; whereas, we're being told we don't really care whether you have a functional relevance to our grid. You're putting your facilities in if you want to be part of this IOU, the 69kV, I mean, of this RTO. That's the 69kV issue I mentioned. I see a philosophical distinction and a conflict between those two points.

And, finally, the revenue shifts from de-pancaking. We are not -- we recognize there is obviously a need to insulate people from that. FERC realizes that, we believe, GridFlorida's proposal will do that with the five-year zonal rate and then the five-year phase-in beyond that.

It's interesting to note that PJM, I think it was, was at the end of their license plate period and they're now requesting extension, you know. Even though we lock the five-year license plate in and then a five-year transition over to a zonal, I mean, a postage stamp rate, there's no reason that if we get to the end of a four- or five-year period and find that there needs to be a change, that it can't be, can't be sought at that point, which is what PJM is doing.

So, you know, we live, we learn as we go along. I think the objective here is to try and get it right at least in the short-term, leaving open the options to try and then broaden that out as we have the benefit of experience behind us. Thank you.

CHAIRMAN JABER: Thank you, Mr. John. One of the things I've been listening for as you all make your presentations are areas where the stakeholders could reach consensus. And with respect to the desire to preserve the tax exempt status, that issue doesn't strike me to be highly complex. Have you all not pursued discussions related to that issue?

MR. JOHN: I think we're, I actually think we're at a point where we're satisfied with the way that things are. But if they were to change, then, of course -- I just simply want to make you aware of how important that is to us.

CHAIRMAN JABER: Okay. But in terms of an issue for this Commission to address as we go forward, there is nothing there we need to address.

MR. JOHN: Correct. Right.

COMMISSIONER JABER: Were there other areas in your presentation that you felt like you were able to reach consensus with the stakeholders and there's no action from us required?

MR. JOHN: Well, that's a tough question. I think we're satisfied with the planning protocol as proposed. The folks at FMPA are not and Seminole. So that's an issue, I know, that you'll probably be asked to weigh in on, even though the FERC eventually is going to view that -- it's part of the OATT, so the FERC will have to speak to it. But we do not have consensus on that, I wouldn't think.

CHAIRMAN JABER: Okay. Okay. And, Mr. Bryant, as promised, I've thought about it a little bit more and I've looked at your comments and now I think I understand what you were trying to tell me. The costs associated with the TDUs in terms of the contributions the TDUs make to GridFlorida, you want that to be included in GridFlorida's rate base. The TDU adder is what the IOUs or what GridFlorida would, would pass on to the end user. Okay.

As it relates to the jurisdictional issue then, FERC will decide the dispute related to how much of your costs get included in GridFlorida's rate base. That's your position.

MR. BRYANT: How much and at what point in time.

CHAIRMAN JABER: Okay. But those costs have an effect on the retail end user. And at what point does the PSC have to dispute those costs or to decide whether it's prudent that those costs are passed or borne by the retail end user? Is it your position that we do not?

MR. BRYANT: Those costs have an impact on every utility's retail ratepayers. Our governing boards will make the decision as to our retail ratepayers. You will make the decision as to the investor-owned utility ratepayers.

COMMISSIONER JABER: When we decide whether to approve the adder and how much, and, if so, how much to include?

MR. BRYANT: As to the investor-owned retail ratepayers. The how much as to their ratepayers is your decision. How much to our ratepayers is a FERC decision because that's wholesale.

CHAIRMAN JABER: Uh-huh.

MR. BRYANT: Did I keep it broad lined?

CHAIRMAN JABER: Yeah. Mr. Naeve, does it appear that I've articulated what your position is with respect to the PSC's involvement with the TDU adder?

MR. NAEVE: I believe you have. I think the question of whether there's a five-year phase-in or a one-year phase-in and all of that is currently pending before FERC. FERC has already accepted the proposal that GridFlorida suggested. The, the munis and the co-ops have asked for rehearing on that, so that's a pending issue.

Then the next question is to the extent that there is an increase in transmission costs through GridFlorida as a result of including these facilities, how are those costs recovered through retail rates? And it's -- the GridFlorida companies have proposed this recovery clause to recover those costs. But that's the issue before you.

CHAIRMAN JABER: Okay. Thank you. JEA.

MR. PARA: I have, Commissioner, I have a short Power Point presentation that I hesitate to do because no one else is doing it, but maybe we could use a little color. And there's no dancing or anything on it or anything like that. But is it -- can the Commissioners see it without moving? I don't want to -- I do also have handouts.

CHAIRMAN JABER: We can see it without moving, I believe. Commissioners, I think if you turn the computer on, you'll be able to see it on the screen and, of course, you can see it behind you.

MR. PARA: And here we'll give you a hard copy, also. And there's some extra hard copies over here for the audience.

MR. PARA: If you can adjust the lights at all. Can y'all see that okay? The lights are --

CHAIRMAN JABER: We've got it in front of us, too, so go ahead.

MR. PARA: Okay. Thank you. Well, JEA thanks the Commission for inviting us to come here today.

JEA has comments on -- we're only going to comment on four of the subjects that were raised in the notice for the workshop. They are Item 8, which is the available transmission capacity and the role of participating owners in determining the ATC; Item 9, the use of physical transmission rights; Item 12, the proposed cost recovery mechanism; and Item 14, the revenue shifts resulting from the de-pancaking of rates.

The first two subjects on ATC and PTRs are also discussed on Page 3 of the comments that we filed. So first let me talk about the available transmission capacity and the role of the participating owners; the participating owners being generally the transmission owners in GridFlorida.

JEA agrees with the latest GridFlorida filing on how the participating owners will be involved with the transmission provider in establishing the available transmission capacity. We think that it's important that the transmission owners have input on that. They'll have the most recent and the most useful information on those facilities. We're the people that are building them, we're the ones that are designing them, so we'll have that information.

Also, the transmission owners own, the "own" part of that is for real, and we're also responsible for those facilities. We're responsible for the safety and the reliability to our customers, and that's why we should have input on that.

There is a concern about when there's disputes between the transmission provider, the RTO and the transmission owner, and we believe that the resolution, the dispute resolution mechanism that's included in GridFlorida provides an acceptable way to take care of those disputes.

On the use of physical transmission rights, this is just a piece of that, it's not clear to us if GridFlorida will allocate physical transmission rights for existing capacity benefit margin. However, that's something that's very important to JEA and it may be something that's only important to JEA.

JEA generally designates a capacity benefit margin as permitted under Order 888 of about 375 megawatts. And this is a reservation of firm transmission capacity between, from Georgia, the Georgia Integrated Transmission System to JEA. And that 375 megawatts will vary depending upon what JEA's dispatch is, which specific units we have online, and also what our load is, which, of course, would vary with the weather.

When we have a capacity benefit margin designated and it's unused by JEA, those megawatt, that megawatt capacity is included in JEA's OASIS posting for non-firm transmission. So it is available for other people to use if JEA is not using it.

We think that JEA is the only transmission owner who has uncommitted interface and designates it as CBM. Tallahassee would also have uncommitted interface. I don't believe that they normally designate it as capacity benefit margin.

When we built the, our portion of the 500kV lines to Georgia back in the early '80s, we did it for economics and capacity, and also we recognize that Jacksonville was located in a far corner of Florida. Before the 500kV lines were built by JEA and Florida Power & Light there was very little, there was really no usable interface between Georgia and Florida. We did move a little bit of power over a couple of small lines but it wasn't significant. JEA was, in fact, in a corner of Florida and could get very little capacity from anyone. So when we built these lines, we knew that we were building more capacity than we intended to lock up with firm generation from the north, but we also knew that that additional capacity would be of great value to our customers, the same customers that took the risk of putting in the money to build that capacity.

So that -- and so what the CBM does is it reserves some of the capacity that our customers paid for and our customers own so that we can use that to provide, to buy capacity and energy from every place except for Florida basically.

Our position is that physical transmission rights should be allocated to JEA equal to our capacity benefit margin at the Florida/Georgia interface. And as I said, I believe this is a JEA-specific item. And I'll say again, it's just not clear to us if GridFlorida is going to do that, and we're having discussions with the applicants. Apparently it's not clear to them either at the moment, so we'll continue to work on that.

Under the proposed cost recovery mechanism we'd point out applicants' response to Staff's question Number 29. They said, "There would be no revenue shifts during the first five years." And yet to us it's apparent that there will be revenue shifts.

In year one revenue requirements for new transmission will be spread across the entire state and that will shift costs. Now in year one it'll be very small, but it will be a shift. And then, as proposed now, from year six on, GridFlorida will be moving towards the postage stamp rates. And I drop back to when the applicant said, "There would be no revenue shifts during the first five years," obviously they recognize that there will be revenue shifts beginning in year six. JEA sees that as a problem. We see that as the postage stamp rate format shifting costs from customers of higher cost transmission systems to customers of lower cost transmission systems, and we disagree with that.

We don't see yet where the Commission has made a decision on that in your order of December 20th. I'll just take one small quote out of it. You said, "The absence of any hard cost data makes any final judgment on the proposed rate structure a risky, risky design," I may have a wrong word there, but a risky decision probably at this time.

It's our understanding that the Commission has not yet ruled on the specifics of the postage stamp rate and we look forward to having an opportunity to participate in the rate structure proceedings whenever they occur.

Item 14 had to do with revenue shifts resulting from the de-pancaking of rates. These first two bullets are from the applicants' response to Staff's question Number 28. They were asked what revenue shifts would occur to the applicants by GridFlorida, and in their answer they talk specifically about short-term transmission service. In fact, under GridFlorida, immediately when GridFlorida begins commercial operation, short-term transmission service within GridFlorida will terminate. And what the applicants estimate for their affected short-term transmission service for 2002, to give an idea of how much this money is, those are the numbers: $4.8 million for Florida Power & Light, $1.6 million for Florida Power Corporation and $1.7 million for Tampa Electric. And these last two bullets are mine. I added those together and got that the applicants' total revenues that are going to be affected, and this doesn't take into account if there's any offsets, would be a little over $8 million a year. That would be less than six cents per megawatt hour that we're talking about. And I think that helps me understand why the applicants don't see that as a big problem.

JEA's short-term transmission service, however, would be about $10 million in revenue a year to JEA, just to JEA. That's a little more than 90 cents per megawatt hour. So you can see why JEA would be more concerned about this revenue shift than the applicants. And I would -- although I don't have the information, I would suggest that JEA is much more affected by this than anyone in Florida. So that's why it's of our concern.

Once again, we're having discussions with the applicants and with some other stakeholders in an attempt to revenue this shift.

I would tell you that a five-year delay is not, is just a five-year delay. It doesn't mitigate the shift. It just says, we'll wait five years and then we'll take your $10 million. So a five-year delay is just really not acceptable to JEA. We're continuing to work in good faith with the applicants and the other stakeholders to try to mitigate this. And I would submit that right now I don't see any action for the Commission, although we will --

COMMISSIONER DEASON: Explain to me what the $10 million is again.

MR. PARA: Short-term transmission wheeling, primarily that JEA --

COMMISSIONER DEASON: Is this revenue you get now that you would not get under the proposal?

MR. PARA: Right. Yes, sir. Yes, sir. And it's almost all import over our ownership rights in the interface between Georgia and Florida.

COMMISSIONER DEASON: So you're not willing to share that for the benefit of the state, I take it?

MR. PARA: Well, we feel like it is benefiting the state. Jacksonville is part of the state and it is -- but, yes. Yes. As a matter of fact, yes, sir, that's exactly the issue.

COMMISSIONER DEASON: Just asking.

MR. PARA: No. You're right on.

Go on there. This is the full quote from the applicants. "There would be no revenue shifts during the first five years from non-TDU municipal utilities that would constitute separate rate zones."

Well, once again, we'd just say JEA alone would experience a lost revenue of $10 million every year and it would begin in year one.

And then finally I'd just like to go over what JEA's recommendations are. First --

COMMISSIONER DEASON: Excuse me. I'm sorry. Let me back up. The $10 million that you get now, is that as a result of FERC-approved tariffs?

MR. PARA: No. We're not FERC jurisdictional.

COMMISSIONER DEASON: So FERC has no say over how that revenue stream comes to you; is that correct?

MR. PARA: Not so far.

COMMISSIONER DEASON: Not so far.

MR. PARA: Yes, sir.

COMMISSIONER DEASON: Okay.

MR. PARA: That's another concern, but not, not for this room anyway.

Our recommendations then are that the participating owners should be involved with the transmission provider, the RTO, in establishing the available transmission capacity because the participating owners know their systems.

We recommend that physical transmission rights should be allocated for capacity benefit margin.

We would like to see the Florida Public Service Commission consider alternative rate structures in formal proceedings where we can give evidence and cross-examine witnesses.

And then finally the very significant revenue shifts from de-pancaking should be mitigated.

And on all but the third one we're in discussions with the applicants and other stakeholders. The third one is up to you. Thank you.

CHAIRMAN JABER: Thank you. Commissioners, do you have any questions, or let's move on to the next presenter?

All right. And that would be, according to my list, Reedy Creek.

MR. FRANK: Thank you, Madam Chairman, Commissioners. My name is Dan Frank. I'm with the law firm Sutherland, Asbill & Brennan in Washington, D.C. I'm appearing today on behalf of Reedy Creek Improvement District, which, as you may know, is a utility serving the Walt Disney World Resort area.

Reedy Creek appreciates the opportunity today to address the Commission with respect to the development of GridFlorida. We will not cover all of its concerns and proposed revisions to the GridFlorida documents in these comments. Its concerns and specific proposals to improve the GridFlorida documents are set forth in its written pre-workshop comments and its comments submitted to FERC and to the IOUs and other stakeholders throughout the stakeholder process.

Instead today we'll highlight several important aspects of the GridFlorida proposals as filed with this Commission in March 2002.

First, I'd like to provide a brief description of Reedy Creek and its interest in the GridFlorida proceedings. As you're aware, Reedy Creek is a political subdivision of the State of Florida established by statute to provide utility services, including retail electricity service within its boundaries.

Reedy Creek's electric system is designed and maintained to serve the needs of its retail markets in the Disney World Resort area, principally theme parks, hotels, other tourist-related businesses, and commercial and residential customers in the service territory. Reedy Creek is a municipal system and it's governed by its board of supervisors.

Reedy Creek both generates and purchases electric capacity energy which it resales at retail. It operates a network of distribution facilities, including certain 69kV lines designed to meet its utility obligations. As noted, its system was built as a distribution system to serve its retail load.

Reedy Creek is very concerned about the impact that GridFlorida's formation and structure will have on its ability to continue to provide highly reliable service at reasonable prices.

Reedy Creek has actively participated in the GridFlorida stakeholder process, including submitting written comments and proposed changes to the IOUs. Like FMG, Reedy Creek sees RTOs as coming and is evaluating its options.

Reddy Creek recognizes that others have addressed both here today and in written comments the issues identified by the Commission Staff in the 14 issues. Reedy Creek, therefore, today will focus its comments on several specific areas of concern that deserve the Commission's attention, in particular on certain aspects of the planning and operating functions that will be performed by GridFlorida including issues of reliability and certain issues related to transmission pricing.

First, on planning, Reedy Creek has a unique customer base which has a very strong interest in preserving the reliability of electric service at reasonable rates. Its customers' nearly legendary attention to details and consumer satisfaction impose additional demands that Reedy Creek is committed to satisfy. As a result of its unique customer needs, Reedy Creek also has a strong interest in providing services in a manner that is sensitive to the reliability, aesthetic and other business needs of its customers.

For example, it constructs underground facilities in almost all cases in order to protects its customers' reliability and aesthetic interests. Its maintenance programs for its system are stricter than typical utility maintenance programs. Reedy Creek builds in a redundant capacity for critical power facilities so that its electrical system will continue to deliver reliably, even if a line or a substation is lost.

Its maintenance work is done during nighttime hours to the maximum extent feasible in order to avoid customer business disruptions, and it often has to construct new facilities on a short turnaround time frame to accommodate its customers' needs for new facilities. At the same time, its customers base is economically sensitive and Reedy Creek endeavors to provide services at reasonable prices.

Against this background we are very concerned that joining the GridFlorida RTO or simply being a transmission customer of the RTO will cause it to lose control over its ability to provide the high quality, reliable and reasonably priced electric service that its customers need and have come to expect.

Reedy Creek recognizes that its need for higher standards may require additional costs and it is not seeking any favors or special treatment here. Reedy Creek seeks only to preserve its ability to adopt and adhere to higher standards for its systems, for its system, and it will bear the additional costs, if any, associated with those higher standards.

Reedy Creek, therefore, has paid special attention to the provisions in the planning and operating protocols in other GridFlorida documents that address a customer's ability to install and operate enhanced or special facilities. These are facilities that satisfy standards that are higher or stricter than those adopted by GridFlorida or are different facilities than GridFlorida would adopt itself.

While GridFlorida standards, if adopted through duly constituted procedures, should be more than adequate for most electric utility purposes, Reedy Creek's customers have unique needs that may demand more stringent standards for purposes of reliability, aesthetics and other business interests. Thus the business needs of its customer base often require that design, operation and maintenance standards be used that exceed those that are typically used in the electric utility industry.

Reedy Creek, therefore, believes -- excuse me. Reedy Creek believes that the GridFlorida applicants had a good start in providing for enhanced or special facilities in the version of the protocols filed with FERC in May 2001. However, as highlighted several times already today, in the March 2002 compliance filing before this Commission, the applicants apparently have deleted and restated the provisions in the planning protocol on enhanced facilities and expedited construction. This has gone far beyond what was required by the December 20th order. The applicants have not explained why doing so was necessary or desirable. In making their changes they also seem to have omitted several important elements. Reedy Creek has outlined these omissions and changes in its pre-workshop written comments, and we urge the Commission to review those written, those written comments. The changes, we believe, represent a step backwards, not forward.

In addition to enhanced or special facilities, as noted, Reedy Creek often has the need for expedited construction of new or modified facilities to meet its customers' needs. In that regard the protocols should continue to provide for expedited construction and maintenance schedules. Foot dragging should not be permitted to cause the delay of putting enhanced or expedited facilities into service.

In our written comments we propose specific language changes to address this issue, but here we emphasize that Reedy Creek would bear the additional costs, if any, caused by expedited facilities.

While Reedy Creek requires the right and ability to adopt and adhere to higher standards than those adopted by GridFlorida, Reedy Creek still may be subject to the other standards adopted by GridFlorida that are applicable to load serving entities and customers of the RTO.

Reedy Creek notes that many of the standards that are supposed to be adopted under the planning and operating protocols have not yet been established. It is imperative that these standards be adopted in a timely fashion so the customers and potential participating owners know what they may be getting into.

In conclusion on planning, the applicants have proposed changes to the protocols that are not required by the December 20th order and are not in the best interest of load serving entities or their retail customers.

As a partial solution to some of these changes Reedy Creek has set forth and proposed in its comments proposed changes that would ensure that it would be able to continue to provide to its retail customers the high quality of reliable electric service that they expect at reasonable prices.

On reliability, Reedy Creek's concerns with respect to preserving the high level of service to its unique customer base extend particularly in this area. Reedy Creek's concerns about reliability of service are even stronger than the concerns of most utilities because of its unique customer base, which has a very strong interest in preserving the reliability of electric service at reasonable prices.

One area in particular is the control that the RTO could have over customer generation under the currently drafted GridFlorida documents. Given the demands of its customer base, Reedy Creek cannot turn over to the RTO complete control of its generation and distribution system if that would mean that Reedy Creek could no longer control key elements of the electrical service that it provides such as maintenance schedules.

As an example, GridFlorida's access to facilities should be limited to reasonable times compatible with the needs of the local utility and its customers in order to avoid interruption of nonutility commercial operations. That access also should be subject to reasonable notice. Such restrictions are reasonable and would not impede GridFlorida's ability to carry out its functions, and the utility itself would be able to carry out its legitimate business activities without undue interference.

Reedy Creek also believes that it would be appropriate to exempt from GridFlorida's control and prior approval those instances in which taking a facility out of service or placing one into service would not have a material affect on the reliability of the transmission system. If the impact of such an action is so slight so as not to affect reliability, no purpose is served in requiring the advanced approval of the grid operator.

Similarly, there should be no -- there should be an exception for maintenance schedules and maintenance schedule changes that have no impact on the transmission system.

Of course, Reedy Creek recognizes that as the operator of the transmission grid the RTO must have a sufficient degree of control of the transmission system in order to ensure the safe and reliable operation of the system. In that regard Reedy Creek would agree that the RTO should have sufficient authority in an emergency situation. Otherwise, to the extent the RTO can take alternative measures that would permit customers to continue to provide reliable high quality service to their customers, then the RTO should be obligated to take such alternative measures.

In summary, the creation of an RTO for the State of Florida should not result in the loss of control of load serving entities or their ability to reliably serve all of their retail customers at reasonable prices.

Reedy Creek also would like to emphasize its pre-workshop written comments on the demarcation point issue. This is the 69kV issue that FMG also addressed. The applicants have proposed a change in the POMA that would deem all 69kV facilities to be transmission regardless of actual function served by those facilities. This change was not required by the December 20th order, and surely this Commission did not intend to sweep in those 69kV facilities that were not designed for and do not serve a transmission function.

Moreover, this issue is before FERC on rehearing, so it is far from settled. In addition, as noted by FMG in its presentation here and in its written comments, there is no stakeholder consensus on this issue, notwithstanding statements to the contrary.

The issue really boils down to being a transmission pricing issue because it affects which load serving entities may be subject to pancake rates under the RTO's open access transmission tariff. The Commission should avoid adopting an approach to facility classification that would unfairly penalize distribution systems that happen to have facilities rated at 69kV or higher.

This is an important issue for Reedy Creek. Its system includes certain 69kV lines that are interconnected with neighboring utility systems. Those lines, like all of Reedy Creek's system, were designed and are operated to serve its retail customers in its service area. The interconnections with other utilities enable Reedy Creek to provide reliable, uninterrupted service to its customers. The proposed change in the POMA may deem these facilities to be transmission without regard to their actual intent and function.

This is how it would work. In the POMA the applicants have proposed to modify the definition of controlled facilities, which are those facilities that would be subject to the operational control of the RTO. Under the proposed definition, controlled facilities would mean all electric facilities in the GridFlorida region that are nominally rated at 69kV or higher. The applicants also have deleted any mention of transmission in this definition. The practical effect of this modified definition is to establish an easily administered bright line test for determining whether a particular facility is transmission or local distribution. Those facilities at 69kV or higher would be transmission with no further inquiry into the actual function served by the facility. The owner of such a facility would then have to turn control over the line to the RTO or face certain penalties.

For example, under the OATT, the owner of a 69kV line that did not turn control over the line to the RTO would be subject to pancake rates. The purpose of imposing pancake rates in this case is to provide an incentive to the facility owner to join the RTO. The ultimate goal, of course, is that all transmission facilities be under the control of the RTO. However, using this mechanistic voltage level-based standard ignores whether a particular line is, in fact, transmission. Based on all the facts and circumstances, including the design and use of a facility, a 69kV line may be local distribution rather than transmission. In that case there is no reason to impose penalties on the facility owner in an attempt to get him to join the RTO. The RTO should have control over transmission, not distribution. Using a mechanistic approach as proposed by the applicants ignores important characteristics of facilities.

Accordingly, Reedy Creek objects to the attempt by the applicants and others to deem any facility, regardless of actual function, that is rated at 69kV or some higher level to be transmission. This proposal is neither required by the December 20th order, nor is it consistent with federal law.

First, in the December 20th order the Commission did agree with the applicant's proposal to use a 69kV demarcation point for determining which of their transmission facilities to place under the operational control of GridFlorida. While a uniform demarcation point based on nominal voltage rating may be administratively convenient, it does not address the threshold question of whether a particular facility is in the first instance a transmission or local distribution facility. The proposed change in the POMA eliminates that threshold question.

Second, FERC's long-standing approach to determining whether particular facilities are transmission or local distribution has been a functional approach. Thus, if a particular facility serves a transmission function, then it is properly classified as transmission. In contrast, if it serves only local distribution purposes, it should be classified as local distribution. In distinguishing between the two, the technical characteristics of the facilities also may be considered, but voltage level is but only one factor in the analysis. FERC never has relied simply and solely upon the capacity rating of a facility to determine if it is transmission or local distribution.

Reedy Creek would like to emphasize that it does not oppose the use by the applicants or others of a 69kV rule of thumb for their own facilities, so long as that rule of thumb is not deemed by anyone to replace FERC's functional test for other utilities that may participate in the RTO.

A 69kV threshold may be appropriate as an initial matter in evaluating the characteristic of a facility, but a utility should not be precluded from demonstrating that a particular facility is local distribution based on the function that the facility serves. There's no lawful or rational basis for requiring utilities to transfer to a regional transmission organization control over facilities that are performing predominantly a local function regardless of the size of the facility.

The applicants and their supporters have no basis to rely solely upon voltage levels as set forth in the revised POMA. Indeed, at the October 2001 hearing before this Commission the applicants agreed that FERC has adopted a multifactor functional test rather than a simple 69kV test whether specific facilities are to be classified as transmission or local distribution. The witnesses acknowledge that voltage level is only one factor in FERC's test, although in their prefiled written testimony they presented various reasons for their use of a 69kV point as a demarcation point and why trying to draw finer distinctions for their systems would be inappropriate. Thus, this Commission can decide that the three IOUs transfer to the RTO of control of the transmission facilities at 69kV and above is appropriate for them without upsetting FERC's test for other utilities.

Finally, it bears emphasis that there is not a uniform consensus among stakeholders regarding the use of 69kV for purposes of classifying facilities. Contrary to Mr. Linxwiler's suggestion, 69kV is not a well-established or uniform test for classifying transmission facilities in Florida. Moreover, as noted, this issue is before FERC on rehearing, so it is far from settled.

In summary, GridFlorida is supposed to be a regional transmission organization with control over transmission facilities. The applicants' current proposal for the POMA would take the "T" out of RTO. Their proposal exceeds the requirements of the December 20th order and in any event is pending before FERC on rehearing.

Consistent with federal law, Florida utilities should have the option of demonstrating that any particular facility serves a distribution function rather than transmission regardless of nominal voltage level. The POMA should be revised accordingly.

COMMISSIONER DEASON: Who do you propose should make that decision?

MR. FRANK: Make the decision regarding --

COMMISSIONER DEASON: Regarding as to whether a particular facility serves transmission or distribution.

MR. FRANK: I believe in the first instance it should be proposed by the local utility who owns the facility. If there is a disagreement whether it goes before FERC or this Commission for a decision, that remains to be seen.

Reedy Creek also would like to have a few words on another transmission pricing subject, which is physical transmission rights. Reedy Creek urges the Commission to continue to require the use of physical transmission rights as a congestion management tool. In particular, Reedy Creek emphasizes that PTRs should be allocated to load serving entities in sufficient quantities to enable them to continue to provide reliable electric service at reasonable rates based on existing loads as well as on load growth. PTRs also should be allocated to a load serving entity following the expiration of an existing agreement in order to prevent the exercise of market power by those who would otherwise control the PTRs.

Finally, as today's presentations and the written comments indicate, there are many unsettled issues in the development of GridFlorida. Reedy Creek would like to highlight one issue of great importance to Florida's municipal systems, the use of powers of eminent domain. FMG already touched upon this issue.

Section 7 of the planning protocol would require that a participating owner use its power of eminent domain, including rights-of-way, for the construction of transmission facilities. Reedy Creek does not object to the IOUs agreeing to provide such eminent domain support. However, it does object to GridFlorida using its power over transmission to try to commandeer the land use powers of local political bodies such as municipal utilities. Reedy Creek's authority and obligations in this area are a function of statute and of its status as a political subdivision of the State of Florida.

While Reedy Creek and other political entities may choose to assist with respect to reasonable facilities in which they would have a direct interest, Reedy Creek cannot make a blanket commitment at this time to do GridFlorida's bidding with respect to a future use of condemnation powers. This issue also is pending before FERC on rehearing.

Along the same lines, the applicant should explicitly identify those provisions of its tariff, of the proposed tariff that would require municipalities to waive their local governmental police powers.

CHAIRMAN JABER: What exactly related to eminent domain is pending at FERC? You said this issue is pending at FERC for rehearing. What part of that issue?

MR. FRANK: The issue -- the authority that GridFlorida purportedly would have to require those entities with eminent domain authority to exercise that authority on behalf of GridFlorida or other third parties.

CHAIRMAN JABER: You don't think that's a state issue?

MR. FRANK: Yes, it is a state issue. But I believe it's actually in the GridFlorida tariff right now and that's why we sought rehearing on it.

CHAIRMAN JABER: Okay.

MR. FRANK: In conclusion on this issue, local governmental bodies like Reedy Creek should not be asked to agree to waive their police powers without the applicants at least having specifically identified the circumstances in which that waiver will be sought. These issues remain important and must be resolved for the GridFlorida process to move forward. And Reedy Creek thanks the Commission for its attention and would be happy to answer any questions.

CHAIRMAN JABER: Thank you, Mr. Frank.

Next on my list, Merit, Duke, Calpine, Reliant.

MS. PAUGH: Good afternoon, Commissioners. Excuse me. My name is Leslie Paugh. I'm here representing Calpine Corporation, Duke Energy North America and Mirant Americas Development, Inc. Joe?

MR. McGLOTHLIN: My name is Joe McGlothlin of the McWhirter, Reeves Law Firm. I appear for Reliant Energy Power Generation, Inc., and to my left is John Orr of Reliant.

MS. PAUGH: Commissioners, the group of us are independent power producers that welcome the opportunity to address you on the RTO. The RTO provides an opportunity for all of us to correct impediments to the efficient operation of the grid. Those correction of impediments will benefit consumers in the form of lower electricity costs resulting from wider choices for consumers.

The joint commenters of the four companies have submitted comments on the following areas: The operating protocol, the planning protocol, generator interconnection, Attachment W or ICE, Attachment T or grandfathering, the POMA, the participating owners management agreement, governance and the code of conduct. We adopt all of those comments, but in the interest of time we'll not reiterate those comments at this time. Rather, our comments will focus on market design.

With me today is Beth Bradley, excuse me, of Mirant to address market design, with John Orr. In addition, we have Joe Regnery to address Attachment T. Go ahead.

MS. BRADLEY: Thank you. We're now proceeding today to highlight some of the key issues of concern to the joint commenters with the applicants' proposed market design. I've tried to outline the presentation you're about to receive in four parts: The objectives for any market design; the GridFlorida proposed market design and its flaws; the joint commenters' proposed market design and the benefit to consumers of that design; and then we're going to talk or make some suggestions or some items to consider in terms of what a day one and a day two might look like for Florida.

Hopefully these slides will be a little bit clearer than some of our comments. This is a complex issue and unfortunately it's fallen on me to describe it or work with y'all on it, and but I hope the slides are a good leave behind. And John Orr and I both look forward to an open dialog and answering any questions that you may have today or in the future.

So with that, RTOs really are independent of the market. And unlike many utilities, they have no incentive, therefore, to discriminate. This will allow consumers with appropriately designed markets to acquire the least-cost power supply to meet their needs regardless of where the plant is located or who owns the generation.

Therefore, some of the goals of an appropriate market design, as we see it, is one that promotes an economic efficiency to consumers, lowers delivered energy cost to consumers, maintains power system reliability to the consumers, mitigates market power for consumers, provides transparent, provides transparent locational price signals for consumers and suppliers and, lastly, increases the ability of load to access the greatest number of competing generating suppliers.

Now let's discuss GridFlorida's proposed market design. It's a bid-based congestion management model with pay as bid in the incremental and decremental market. Under such a bid-based -- and we'll talk about physical rights in a minute -- congestion management system and given the distribution of Florida's generation by large utilities, the utility in such a system as was proposed right now can basically name its price. And, indeed, by its scheduling decisions, the utility may be able to create the congestion it will be paid to relieve or otherwise will require the ISO to rely on its high-priced generation to maintain reliability.

The get-what-you-bid approach really obscures these price opportunities to competitors and the balanced schedule requirement prevents merchant generators without load from contesting such unreasonable market outcomes. How the large utilities will keep from exercising market power in locally constrained pockets is not addressed by the applicants.

The physical rights model grants existing transmission customers physical control over much of the transmission system through the allocation of PTRs, which convey a priority right to schedule generation injections whether or not more economic choices exist for their consumers for merchant generation. It also empowers the physical rights owners to exercise market power by withholding that portion of the transmission system.

While trying to protect consumers from increased cost as a result of directly allocating transmission rights with an annual reallocation of physical rights, this may actually cost consumers more when there are more efficient, less costly generation resources available.

The physical rights, physical transmission rights model has some of the following features. You know your constraint are -- the known constraints are designed as flowgates with PTRs directly allocated. There will be other transmission limitations, for example, on the non-flowgates that are addressed through transmission line loading relief measures and, therefore, or as a result some massive socialization of the redispatched costs. We'll talk more about those a little bit later.

But basically relying on TLRs, excuse me, transmission line relief to relieve certain congestion situations under a physical flowgate model creates undesirable levels of uncertainty on scheduling. Curtailments based on price, however, provide firmness and highlights the value to those entities who might otherwise be willing to modify their generation or consumption patterns.

For non-flowgate congestion, which in the GridFlorida zone may be significant since right now we only know of three flowgates that they've identified, GridFlorida proposes to socialize the redispatched costs. This would, as others have said today, penalize market participants that had absolutely no responsibility for creation of such congestion and drive up the cost to consumers.

Another feature of the market design is that all supply and demand schedules or submittals must be balanced, and any actual imbalances outside the very narrow bandwidth will be taxed. In reality the electric system depends on transmission that flows based on the laws of physics and that all balanced schedules are feasible. The quite complicated incremental and decremental scheme is made necessary by this requirement for balanced schedules. This is the same issue that California experienced. In other ISOs all deviations are simply paid the equilibrium price or locational marginal price, obviating any need for separating, separate incs and decs to be submitted.

In equilibrium the incremental price and the decremental price should be the same since the marginal consequences on price of existing, of increasing generation and decreasing load should be identical.

In addition to the prior shortcomings identified, there are other problems that exist with the GridFlorida market design. The RTO's independence is undermined by the ability of control area operators to ramp automatic generation control generation up and down and the ability of the scheduling coordinators to replace generation lost due to a forced outage with other generation and real-time by allowing the control area operator, who happen to be market participants themselves or affiliates of market participants, to select units to provide regulation service.

In addition, scheduling coordinates with accepted schedules may not, may elect not to submit a decremental bid. At a minimum this may force the RTO into inefficient decisions that are more costly to consumers to resolve the congestion. The potential exists for control area operators to manipulate market outcomes with strategic dispatch of automatic generation control units.

The RTO's independence is further compromised, as we stated in our comments, through the long-term point-to-point agreements, the participating owners' own tariffs, FRCC specifying spending as supplement reserve responsibilities to scheduling coordinators.

The GridFlorida system cannot be reliably or efficiently run through parallel operation control by a number of different parties. Network customers may be denied sufficient physical access through physical transmission rights to purchase the output from new efficient, low cost generators under the proposed design that allows network customers to modify their supply portfolio on an annual basis to get physical transmission rights to the extent any leftovers remain after the initial allocation. This will frustrate market efficiency. Such an efficiency and opportunity for anti-competitive blockade is not in the consumers' interest. Network customers must have equal and flexible access across the network at all points in time since all network customers pay for the network.

The proposed market design is not in the best interest of Florida consumers because there are numerous ways to gain the market or for incumbent utilities to exercise market power by raising prices above the level that would be achieved in a competitive market with many suppliers. For example, there are clear incentives that exist to gain the scheduling process by overscheduling generation and/or load in advance of real-time and thus driving up congestion costs.

What the balanced schedule design claims to deliver at a scheduling coordinator level in terms of balanced schedules each hour indeed would be out of balance after the transmission constraints, unit startup, shut down and minimum run times are factored in.

As a practical matter, the ISO will need to take actions at a regional level and commit additional units or deny specific schedule requests regardless of whether there are PTRs, physical transmission rights, supported or not in order to assure the reliable unit commitment schedule for the day.

Further, incumbent utilities or their affiliates under the proposed market design have the ability to deny physical market access or extract monopoly rents from such access. They assume real-time energy market control, they run the regulation ancillary service market, and they gain socialization of pricing and remain undetected by virtue that there's no transparent pricing to consumers with this model.

No ISO or RTO has implemented this physical transmission rights model. Why would GridFlorida want to spend additional monies on a design that is unworkable, replicates features proven to be problems in the west and in conflict with the rest of the eastern interconnection and will be incompatible with the neighboring RTOs?

This is only going to exacerbate the seams issues. Basically coordination and consistency of the wholesale market design with the rest of the eastern interconnection is essential to avoid walling off Florida and its consumers from the benefits of broader competitive market, as FMPA has stated today.

Consensus around a financial rights-based congestion management model, LMP, and the use of a day-ahead clearing market instead of balanced schedule requirement is not by chance. The brightest minds and the most vigorous debate and the demonstrated failure of other designs have converged all industry experts around this model.

I'd like to continue with talking about some of the fallacies of the physical flowgate model. Congestion will occur on a manageable number of commercially significant flowgates that can be identified ahead of time.

While GridFlorida has only identified three such flowgates, market experience elsewhere indicates that this will grow or change as competition drives more efficient Florida-wide results.

One of the factors that the Commission has looked at here is that in the future while GridFlorida may become its own RTO to begin with, you've also said we want to make sure that it's adaptable to other neighboring RTOs. And I think that's something we've got to keep in mind as we go through all of this.

This market design seems to ignore the need for the

ISO to review unit commitment adequacy and, if necessary, order units online in advance of real-time to assure the short-term reliability. This is clearly at odds with the proposal to review whether schedules are sufficiently covered at 30 minutes prior to each hour.

The ISO will need certainty on which units will come online well before 30 minutes in advance of the hour. Many units require longer startup times. Similarly, the ISO will need assurance that the set of resources upon which it relies on in one hour will be there in several contiguous hours. Yet the physical rights, physical transmission rights review evaluates only individual hours and ignores these intertemporal constraints for startup, ramp time, et cetera.

Finally, these unit commitment scheduling realities mean that even physical transmission rights-based schedules are subject to curtailment in order for the ISO to assure system reliability. Whether they are curtailed or additional redispatch or other generation is needed to support the original PTR schedule, the costs of redispatch are socialized and no LSC is fully hedged, even if they hold all the PTRs to support their schedules.

Why we think an LMP financial transmission rights model is superior to a physical rights model is that because it relies on clear, transparent price signals and provides nondiscriminatory access to and optimal utilization of the entire transmission system.

An FT -- a financial transmission rights model makes fuller, excuse me, more efficient use of the grid. There's no withholding of rights; no market participant can withhold transmission capability from any other market participant as can be done with the proposed physical transmission rights and balanced schedule requirement proposed by GridFlorida.

Financial transmission rights also offer greater benefits to the holder since the financial transmission rights continue to have value, even if the ISO needs to reject a self-scheduled request of the holder, which is going to happen with the, out of necessity with any model. The same is not true for the, for the physical rights model. While nonphysical transmission right holders are allowed to buy unused physical rights, physical transmission rights, such schedules cannot be confirmed until 30 minutes prior to the hour; far too short to enable any, many, excuse me, generating units to satisfy startup time and minimum run time constraints. Thus, it limits the type of generators to only peaking units when other more economic units may be available.

Financial transmission rights that are issued must be simultaneously feasible. There is no distinction between commercially significant flowgates and non-flowgates. With financial transmission rights there's no linkage between who is covered and a physical curtailment priority.

We believe that enforcement of overforecasting of load or generation is likely not to be enforceable, hence the cost to efficiency would be great and the value to assuring reliability low. Anyone can schedule generation injections. Firm service really comes from the willingness to buy through congestion.

Transmission customers who purchase financial transmission rights from a generator to a load get the benefit of meeting their energy obligations as if the generator were located at the same point. A transaction can be fully hedged, partially hedged or unhedged without affecting scheduling. In fact, a financial transmission right holder can receive the value of that right, the locational price difference, and allow a generator which is lower in costs than its own to meet its energy needs, thereby producing savings for consumers.

Locational marginal price/financial transmission rights model acknowledges that electrons flow according to the laws of physics and actual system conditions, not contract paths or physical transmission right evaluations at 30 minutes in advance of the hour.

The use of locational marginal pricing sends clear signals to those causing congestion and relieving it and will actually decrease the incident of transmission line loading relief and improve deliverability and produce lower aggregate costs to meet aggregate Florida demand.

Financial transmission rights facilitates trading and increases liquidity. They can be traded to any party looking for a financial hedge and they can be traded to pure financial players as well.

Physical transmission rights will only be of interest to buyers that actually want to physically schedule over a flowgate, resulting in fewer participants and a less liquid market. Okay.

MR. ORR: I think, you know, that kind of lays out the benefits of why LM, what we call the LMP model is superior to the physical flowgate model. And I think one of the things I heard from other commenters today was that there was this perception that physical transmission rights somehow garner greater reliability. I held the physical right to move this power across these interfaces and, therefore, I was assured of getting my load served, and somewhat touting that as a feature that people really needed to have.

And, in fact, in practice in places both in New York and in PJM that have implemented this system successfully, what happens is the RTO provides service to all the loads and they don't worry about who's holding physical rights across gates in those systems. They serve all the load. And then what happens is the prices are settled out so you see actually what it costs to serve different people's loads. That's what this system is based on. It's not based on, you know, some financial pie in the sky that doesn't assure that load gets served. And I wanted to make that clear here because I thought there was some perception that physical granted more reliability than financial, and that's not true. The financial just simply tells you what it costs to provide that reliability to people.

CHAIRMAN JABER: Okay. But -- all right. Mr. Orr, then elaborate on the importance of having the financial rights model as it relates to neighboring RTOs or how to better address the seams issue, because I didn't understand that either.

MR. ORR: Well, right now you have SETrans headed down the road of doing locational marginal pricing essentially. That's where they appear to be headed, towards standard market design. As a matter of fact, the only entity in the whole eastern interconnect that isn't already there and is kind of doing a hybrid of these two is the midwest ISO. Everybody else has gravitated towards LMP.

And what will happen is that if you -- you'll isolate Florida, if you do physical transmission rights. The only people that will be able to move across that interface between Florida and, say, into Georgia or into the rest of the southeast or the rest of the eastern interconnect will be these physical holders that hold them for purposes of scheduling. And what it means is that customers in Florida that choose to shop around the rest of the southeast for lower incrementally-priced generation will not be able to do that very easily, if at all, unless they go to the person that holds that PTR and says, hey, could I buy some of those from you in a secondary market? Then they'll have rights to transport that power in. And if that person that holds the PTR wants to say, well, you're going to pay me some outrageous price for it, there's no, there's no check on that.

Now that person also may say, I'm going to hold it for my load, and do what we would call physical withholding from the market of the PTRs.

CHAIRMAN JABER: Would they go, would they go to the person that has the physical transmission right or would they go to GridFlorida or the neighboring RTO?

MR. ORR: Well, if they wanted to do a long-term transaction in advance, arguably they would need to go -- to hedge themselves against congestion risk and to make sure they had capacity, they would need to go to the holder of the right and say, could I buy it from you? Because GridFlorida didn't make any provisions for initial auctioning of the rights.

So in order for somebody to get, to do a three-year deal with a cheap generator up in Georgia, they'd have to go to a person that had been allocated the PTRs.

Under financial, the person could take the risk of that. They could say -- they could do two things: They could buy, in an auction they could buy a financial transmission rights, which would hedge them against the price variances between the two points, true them up to the cost differential between the points so that they were assured of a fixed price for transmission between the points is the effect of that, and/or they could take the risk and say, well, I bet prices aren't going to blow out much between these two points, that what we would call the basis differential isn't going to expand between the two points. And what would happen then is the person would say, I'll just take the risk and I won't go buy this FTR hedge and I'll just pay the difference, if it actually exists, between those two points. And then you could very easily merge SETrans' system with GridFlorida's. But with this physical PTR, what I would call barrier, people are going to control those interfaces and limit the people that don't have those PTRs ability to shop around for cheaper resources in other regions.

CHAIRMAN JABER: And none of those issues could be addressed in the individual seams agreement?

MR. ORR: It would be difficult. I think it would be very difficult to do. If you grandfather those rights to people sitting here in Florida, then the people that happen to be in Florida also but didn't get any of those rights would not have the opportunity to do the shopping or they would be beholding to the holders then.

COMMISSIONER DEASON: Explain to me your statement that PTRs do not enhance reliability.

MR. ORR: Well, they're no more -- what my point is -- LMP is not a downgrade of reliability. A financial system is not a downgrade of reliability to a physical system is what I'm saying. In fact, they're probably the same. If the RTO is running the system and balancing the load minute by minute and calling on redispatch to meet the load as it changes or regulation service and the ancillary services involved as well, then you get the same level of reliability. And I think some people think, and I've heard this kind of misquoted by various people here and elsewhere, that if I hold this physical contractual right to flow in a certain direction, which is a flowgate right, that somehow magically I have more reliability than if I am relying on a financial congestion management system.

What I'm saying is that it's the same reliability. The RTO is going to run the system, redispatch generators as necessary to serve all the load in the region. I mean, in fact, what we saw was is that California had serious problems because they created something that looked a lot like flowgate rights across their Path 15, and they had to go back and manufacture because they had a balanced schedule with a physical rights type model across that path. Then they'd go back and manufacture sinks (phonetic) for people to submit schedules to the ISO in real-time to maintain reliability. So we saw that the physical rights model, when things started to break down, became actually a reliability issue. It became difficult to schedule in enough generation into that state to meet their load and they had to artificially do it.

But my point really is that there's no real reliability difference. That's -- giving a physical right to somebody doesn't mean that they have a higher probability of keeping their lights on than if they had a financial right.

CHAIRMAN JABER: I guess I didn't, I didn't hear that. I don't know if that alleviates your concern or not.

MR. ORR: Okay. I just wanted to make sure.

CHAIRMAN JABER: I did not hear as an argument for keeping the physical rights fixed for some period of time to be a reliability issue.

MR. ORR: I just wanted to make sure that it wasn't because I think some people have that impression.

COMMISSIONER DEASON: Well, do PTRs insulate load serving entities from transmission price spikes?

MR. ORR: Actually, no, would be my answer. And the reason why is because of the socialization. When you have to draw the flowgates and lock them in in advance and then what I would call the system topology changes, in other words, the actual physics of the system are changing, that means you arbitrarily drew the lines based on some probability or some certain number of hours and that's how you drew, say, the three flowgates we're talking about here, which means that we knew we had to socialize something in certain hours. So that means that in certain hours people are going to have to pay because they locked themselves in the flowgates. With --

COMMISSIONER DEASON: Explain that. How certain people will have to pay -- explain that.

MR. ORR: Okay. Let me think about how to say this. When we set the flowgates, we're planning on a certain number of generation resources being on a certain load level and the like. But in real life we know that that moves all over the place and we're going to need to redispatch. So we locked down people contractually into PTRs and said to them, if you're holding PTRs and you're flowing across this line, we're not going to charge you a dime for any redispatch we have to do. That's what congestion management is. Right?

Well, what happens is everybody else who happens to be, say, downstream of that flowgate or everybody including the PTR holders that happen to, that happen to have, are flowing across another line that suddenly experiences congestion that we didn't have PTRs on, handed out on, all those people now have to pay the cost of that redispatch.

The difference in LMP is that people can actually buy hedges between the nodes on the system. And when I say nodes, that's either a point of injection on the system or a point of withdrawal on the system that they think replicates the pricing differential across the paths that their resources will flow across to them.

So if I have a generator at A and a load at C, right, I can go buy the hedge, the FTR between A and C directly. I don't have to go worry about buying a PTR on Line 1, having to get power flow between those two points, and then a PTR on Line 3 and a PTR on Line 4 and then take risk as to if Lines 5 and 6 also have congestion.

So the beauty of FTRs in the financial market is that I can perfectly hedge myself against the price deltas between the two points that I'm transporting across.

COMMISSIONER DEASON: Who do you buy that from, the FTR?

MR. ORR: The FTR is actually -- you buy them from the RTO is the best description.

MS. BRADLEY: And they would be just allocated or auctioned very similar to what we're talking about with the PTR model. There's really no difference in that kind of setup.

CHAIRMAN JABER: Well, except the auction, except the risk of having those rights auctioned.

MR. ORR: Right.

MS. BRADLEY: That's true. Right.

CHAIRMAN JABER: And that, that is something that in terms of --

MR. ORR: Well, let's -- well, just as a frame of reference here on that subject. PJM came down and spoke to GridFlorida, okay, and this was -- it was a long time ago now, two years ago, maybe 18 months. And Mike Cormas (phonetic), who's the general manager of operations, okay, in PJM, the guy who runs that system day to day and runs this part of it, manages congestion, said PJM allocated those FTRs initially, said if he had to do it again in order to create more flow and to allow more people to hedge themselves, he would auction them. And he's the person with the most experience in the United States in running that system.

So, and that's really one of our big messages here is that the LMP stuff is a proven method. No one has successfully implemented a flowgate model. I'll let you go.

MS. BRADLEY: You'll let me go.

MR. ORR: Unless they have more questions.

MS. BRADLEY: Okay. Let me go forward. I want to thank John for actually helping me shorten this presentation.

Just very, very quickly picking up on Slide 7, the fallacies of a balanced schedule requirement is that each scheduling coordinator has complete control over its generation schedule. It does not. The ISO does. It assures system reliability; we've just talked about that. It does not adversely affect efficiency and it does not adversely affect competition. All those things I think you'll see that it does do.

So moving a little more quickly on to what the joint commenters' proposed market design would be, we would basically be asking you to reject the GridFlorida currently proposed market design and adopting the FERC standard market design, which may have to be tweaked for regional differences, et cetera. But the way we see this, this is a voluntary day-ahead market that will ensure reliable unit commitment and sufficient capacity to meet the forecasted load.

There's no balanced schedule requirement to restrict the ISO's efficiency in managing congestion and maintaining reliability. It does result in least-cost dispatch of generating resources. It's transparent via visible spot market prices being posted. There's flexibility for market participants because it allows for a bilateral, spot and self-scheduling; everything that you have today.

It can be implemented across multiple control areas, and locational marginal pricing or LMP is used for real-time congestion management as spot market. It's also a proven model, as John has said, and it will decrease transmission, TLRs and increase deliverability.

GridFlorida consumers want to be protected from congestion costs and want to retain existing transmission rights that they currently are entitled to and have price certainty around those costs.

FERC's proposed standard market design has outlined a new network access service that is financially, that is a financially-based solution. This allows, as I've said before, all transactions to proceed on a physical basis disciplined by locational marginal prices, no socialization, with price certainty achieved through the financial transmission rights coupled with this real-time LMP congestion pricing. This provides a much more efficient model for addressing aggregate Florida needs and is in stark contrast to the current GridFlorida proposal which is physical rights-based and all transactions will not flow unless the owner holds sufficient rights, thereby creating the possibility affording less economic dispatch and gaming.

Some additional benefits of our proposal is that we do believe that congestion pricing will provide incentives for new construction in the right locations, preferably near the load centers. It can improve the liquidity of the marketplace with financial products that balance out with the physical transactions, some transparent spot markets, hub-based pricing much like the gas market, and levels the playing field for structuring market-based products to loads.

Getting ready to wind up, we would like to propose for consideration a day one interim market design proposal that would basically be one-stop shopping, single tariff, a single OASIS where network resource interconnection service is offered to all generators, RTO-wide network transmission service is implemented and pancaking eliminated. Network customers would have the right to use the network transmission delivery service to purchase from any generator interconnected to the transmission system or over external interfaces at any point in time. There wouldn't be any restrictions to the annual designation of rights. Also, your network customers could continue to self-schedule their own generation or authorize self-scheduling of purchased generation a day ahead in intraday or real-time time lines.

Customers with existing point-to-point reservations would convert their rights to a new network transmission service. We see ancillary services continued to be provided by transmission owners where applicable and other generators if we had FERC-approved tariffs for those ancillary services. And then generation adequacy could be handled bilaterally with enforcement by the PSC.

On day two we would hope that by then we would be able to implement some kind of standard market design. FERC's NOPR will be out in July. I know they're discussing it today as we speak. Hopefully we will get participation by all stakeholders, including the PSC via comments, workshops, et cetera. And FERC has promised us, and I think they're going to try to keep to this, a final order by the end of this year.

So it's kind of two-step get something started in GridFlorida now and then wait and work more towards getting the standard market design that's going to be acceptable and, I'm looking for the right word, compatible with the other RTOs in the region.

And with that, I turn it back over to Leslie.

MS. PAUGH: I'll turn it over to Joe Regnery.

MR. REGNERY: Good afternoon, Commissioners.

COMMISSIONER DEASON: Before we do that, let me, let me ask a question.

John, I'm trying to understand the big picture, and we've gotten, I think, a whole lot more detail than we probably need at this point and we don't really see the big picture yet, at least I don't. Maybe I'm speaking for myself.

Explain to me in your point, from your point of view what model or system is most likely to result in the least-cost generation being dispatched to the largest number of customers, or is that a problem?

MR. ORR: The LMP system does that.

COMMISSIONER DEASON: All right. That does that. Why does it do that?

MR. ORR: Because it allows the RTO itself to dispatch the system independent of worrying about whether people have these rights called PTRs in their hands to move their generation to their load.

COMMISSIONER DEASON: So you're basically talking about the most efficient way to allocate a scarce resource;

i.e., capacity on the transmission system.

MR. ORR: Right.

COMMISSIONER DEASON: And you're saying that the LMP is the most efficient way to allocate those resources.

MR. ORR: What you need is a centralized security constraint dispatch essentially is what we're talking about here. Okay?

COMMISSIONER DEASON: You can't have transactions take place that are going to jeopardize the physical nature of the system; correct?

MR. ORR: Right. Exactly. And that's what I mean by security constraints.

COMMISSIONER DEASON: So within those constraints.

MR. ORR: Exactly. And what LMP does is it sends, it makes sure that people are seeing the true prices associated with making deliveries to various points on the system. And so that means that customers and people that are shopping to serve their load can then see this is the most efficient place for me to buy and move from; this is the most efficient place for me to build a new generator, if I want to build a new generator; this is the most efficient place for me to conduct some type of swap transaction with someone.

COMMISSIONER DEASON: And this leads me to my next question. What system best optimizes decisions as to whether you enhance transmission or you build new generation?

I mean, there's a tradeoff between the two. I mean, there are, it seems to me --

MR. ORR: Actually it obviates where one or the other should be built, more than likely.

COMMISSIONER DEASON: Okay. Explain that.

MR. ORR: Because you can see -- you can see where price deltas between two points on the system, how disparate they are, I guess is the way I would phrase this. And in a very high priced region at a node you can then evaluate the cost of a line to get from one node to that node or the cost of plopping a generator right at that node that would lower the price on a marginal basis.

COMMISSIONER DEASON: So you're saying the price -- there's transparency in the price and the information is there and people can take that and make what they consider to be the best decision --

MR. ORR: Absolutely.

COMMISSIONER DEASON: -- and then they take their chances in the market.

MR. ORR: Absolutely. So what it does is -- now this doesn't mean that -- at some point someone has to decide and the RTO function should be that it sits there and says, okay, I've got congestion and prices are blowing out between point X and point Y, okay, and I want to rectify this because people are paying, we decided this is no longer socially acceptable to have this disparate price or that someone has localized market power at this one point and that's the reason the price there is so high. So there's two ways the RTO can fix that; right? They can go build a new transmission line to make more generators available to that point that was having such a high price or they could go out and encourage a generator to build at that point. Right?

Now hopefully what you would see is that generators in particular that saw a high price at a point would just be clamoring to jump in there and build a plant there. Right? That would be probably the easiest, quickest solution, considering how difficult it is to site transmission lines.

But, at the same time, the RTO, as part of an integrated planning process, ought to start looking at this routinely and going, okay, I need to put lines here and generation here. And maybe what they can do is even solicit bids from people and they can say, shoot me a price to build me a new line between these points, shoot me a price to build generation here or, you know, give me an idea of what that's going to cost, and then they make an evaluation, and put them in a position to -- and maybe with your advice, right, since you have the Grid Bill here in Florida, you start working together to come up with this is probably the optimal solution and let the RTO be the judge of that and the market be the judge. The market is in the signal and then let the market coupled with some RTO oversight for long-term planning address the problems, start addressing the problems over time.

This is actually what's going on in Texas. I mean, they're building something like $800 million to $1 billion worth of transmission lines as a result of fixing congestion that they saw once ERCOT went live. That was actually, it was mandated eventually by the PSC there.

But, you know, you can see that they saw a problem, they knew they were going to have price blowouts, and they went in and said we're going to build some lines to fix it because we know over the long-term the benefits of building those lines will offset the costs we incur to build them.

COMMISSIONER DEASON: Explain to me why under a physical transmission right approach you could not go in and obtain those and there basically be a market for those and that serve the same purpose.

MR. ORR: If you didn't pay anything for them and you were the holder of them, what would be your incentive to ever sell them to me?

COMMISSIONER DEASON: Money, green. I mean, everybody has that -- I mean --

MR. ORR: But if you're, if you have no -- I don't think -- I think people want to hold onto them because they're only going to be valuable when those lines begin to fill up and then you're going to need to move your power. I just don't think people are going to --

COMMISSIONER DEASON: That's market manipulation, what you're just describing there.

MR. ORR: Well, that's what I'm saying. I think it's a bad idea to even set up a system that could work that way. I'm trying to not -- make it obvious and transparent so we can all see what's going on. That's what LMP does. It lets every node on the system see what their price truly is to serve load at that node on a marginal basis, what that next megawatt of load would cost to serve it.

CHAIRMAN JABER: One of the things we articulated in the order was the notion that we have to allow time for the GridFlorida companies and the stakeholders to identify where the flowgates are. And to the degree there are some, then fine. Perhaps, you know, initially we should look at the flowgate model and the physical rights, physical transmission rights approach because of the idea that, that some costs might have to be socialized. Your approach would make it unnecessary to even look at where the flowgates are; right?

MR. ORR: Correct.

CHAIRMAN JABER: And you also referenced another state with a hybrid of the PTR and the financial model. How did they do it? How did the hybrid work?

MR. ORR: Well, they're -- to be polite, it's not working. They're struggling with how to integrate the two systems and they've resulted in an impasse basically. And this is the Midwest Independent System Operator. They have a web site that you can go see, you and your Staff can go see.

CHAIRMAN JABER: What is it, John?

MR. ORR: The Midwest -- I think it's WWW.MISO.com, M-I-S-O. Oh, that's right. They've had two or three. MidwestISO.org.

What they are doing is trying to create a system where they hand out physical flowgate option rights as well as create an LMP system. And the guy who is designing it is a very knowledgeable Ph.D. who is to the point where I think he's just about to throw up his hands and say I don't know that I can do these two things together. And they really have hit an impasse in designing that as a result.

CHAIRMAN JABER: One of the things we, at least it was discussed in the order was the notion that you could start with the physical transmission rights model and to the degree there are no flowgates or the PTRs are not being used, they could be auctioned off. Does that satisfy your concerns at all in terms of preventing a manipulation of moving power to the degree that those holders of the rights aren't willing to sell?

MR. ORR: I don't think they'll be -- I don't, I don't think that's a good model to put things in people's hands for free ever. I just wouldn't go down that path because of exactly the discussion, discussion Commissioner Deason and I had.

CHAIRMAN JABER: But if you were worried that the holder would not have an incentive to sell the PTRs, if we required or imposed some sort of requirement for them to participate in an auction, that doesn't satisfy your concern?

MR. ORR: If you're talking about an initial auction of the PTRs, this is just assuming we're going to live with PTRs -- remember, I don't want to do that anyway -- but let's say we're going to have -- and if we did an initial auction of all of them, not leftover ones, because I don't even know if there would be leftover ones for starters, but I haven't looked at the numbers on that. Okay? I think if you do flowgates and you do PTRs, it's a good idea to auction them initially. I wouldn't just hand them out. I'd make people value them. I'd decide what it was worth to them to have them.

CHAIRMAN JABER: Is that something the RTO could do? Is that something GridFlorida could do?

MR. ORR: Yes.

COMMISSIONER DEASON: If they're auctioned, who receives the proceeds and how are they, the benefits of those proceeds utilized?

MR. ORR: I don't know. I have not discussed this with other generators, before I answer the question. And you may differ, but there's two ways of giving out the money from the auctions.

One is that you could set aside the money -- well, really there's three. You could set aside the money and put it in a pool and say, all this money we collected from these auction of PTRs, what we're going to do is we're going to set that money aside and then use it to build lines to alleviate the congestion. That's one option.

Now that makes a lot of people in the room nervous and for good reasons, because some of these people have been using these lines for a long time and they want to have some ability to feel free to use them again, okay, and to keep someone from going in and paying an astronomical amount that, that they could not compete with to use the lines.

So option two is what, is something that Reliant has worked on internally and that is, and something that was originally thought of in what was called Desert Star or DStar, it's had three or four names, and now it's called West Connect or something like this out in Arizona, and that is you take the money from the auctions and you allocate it back to load serving entities or to actually, yeah, actually to, yeah, we'll call them load serving entities based on their load ratio share. Okay? And what that means is you allocate them back money out of the auction pot based on their actual usage of the system on an after-the-fact basis.

And what this means is that they can go bid in the auction then. And if they buy just what they need and the market clearing price clears the auction for all of the rights at that PTR that they were using, they're going to be perfectly hedged. They're going to get all the money back, if they bought what they needed. If they tried to buy more and kind of corner the market in PTRs, they're not going to get all their money back in the auction. That's the risk they take for the incremental that they go and try to buy above their load. Right?

So this is a system where people that have been, we'll call them traditional users of the system and feel hurt by losing the ability or losing the grandfathering, they can go in and they can participate in the auction, they can bid as much as they want, but we don't just let them bid to be a price taker because we want to send a price signal for what things should be valued. Right? We let them bid as much as they want. And as long as they're bidding and buying just what they need based on their anticipated flow across that flowgate, they're going to get their money back one for one. And so they're not harmed at all and they, and they get to serve their load.

So as a person that is serving their load in this traditional fashion and doing a good job of doing load forecasting and the like, they're perfectly hedged. They have no risk whatsoever of this.

Now what they are at risk for in the PTR system is the socialized downstream congestion. Don't forget that that's out there. They haven't protected themselves with that. But from an auction standpoint we can give them the money back.

Now maybe the best solution, because we want to get rid of congestion over time, is some combination of one and two. Take a little bit of the money and set it aside, say, 10 percent just to throw out a round number, and set it aside to build up a fund to alleviate congestion over time, and then take 90 percent of the money and hand people back 90 cents on the dollar for their actual usage. So that's a way to deal with auction revenues.

CHAIRMAN JABER: Let's continue.

MR. ORR: It can be done with financial rights as well. If you were going to -- if you wanted to auction FTRs, you could do exactly this mechanism.

MR. REGNERY: The one thing I wanted to say in follow-up to John is that physical transmission rights, in response to Commissioner Deason's question, do not give any form of price signal to the marketplace other than with respect to that physical flowgate alone. So you never gain any knowledge from the marketplace and you never create the efficiencies that you want with respect to least-cost generation going to load. You never achieve that. You have to assume that the initial allotment of flowgates is absolutely accurate and we know it never is. It wasn't in California, it won't be in Florida.

LMP gives you that pricing. It allows you to go from node of interjection to node of takeoff. And every time that occurs, you gain a price signal, you gain a history. Okay? So you as a power consumer, wholesale power consumer, can then make a judgment to whether or not you want to self-build a new generation point, buy generation from someone in a locale that's closer to you, or it gives a price signal to the transmission system itself where you would go and tell the RTO, we would like to expand the system. Without that you never achieve that efficiency. But I wanted to --

CHAIRMAN JABER: I guess here's a question that will not, probably not make sense, but I'm going to throw it out here anyway.

Does the LMP model create congestion in and of itself or does it have the potential of creating --

MR. REGNERY: The fact of the matter is, as John was absolutely correct, electrons flow where electrons flow. They -- if load is taking demand off of the system, generation is putting it on the system, it will go according to physics to those places. Whatever we do from a contractual perspective with regard to a PTR or with regard to an FTR is irrelevant. Load is going to go where load is going to go and it's going to suck from where the generation is. All right? And that, that is -- the only difference is a question with respect to how it is financially cleared; whether or not it is balanced off of an LMP model where you have financial transmission rights giving a price signal from a nodal perspective versus whether or not you buy or auction or allot a physical transmission right and make a contractual scheduling, balanced scheduling arrangement. That's the only difference.

CHAIRMAN JABER: Okay.

MR. REGNERY: Joe Regnery, I wanted to thank you for letting me come and speak with you this afternoon. I didn't really want to speak on market design, not that I haven't, don't have an interest in it or a working knowledge, but I, I, Beth and John have lived in this world a lot longer than I have with respect to their involvement in PJM and in ERCOT and other areas where --

CHAIRMAN JABER: Apparently misery loves company, so.

MR. REGNERY: Exactly. Where LMP works. I wanted to actually talk about kind of a follow-up to something that I had spoken to y'all before on, and that was interconnection.

Part of, part of the current tariff has a, interconnection procedures and an interconnection agreement. I would ask that you reject the proposal that has been submitted by GridFlorida and we turn our attention to the current docket at FERC and the results that are coming out of the NOPR. The rulemaking is being established associated with procedures on interconnection and also on interconnection agreements. And I would ask that we, we, we toll any resolution of those issues pending that resolution at FERC.

The other aspect that I wanted to comment about was changes to Attachment T, which Mr. Miller for Seminole Electric and the representative from FMPA have spoken to, and that goes to a question of changes to Attachment T and the December 15th, 2000, date.

I support wholeheartedly Mr. Linxwiler from FMPA and Mr. Miller in their conclusions associated with Attachment T and their representations today. Any changes to that December 15th, 2000, date should be rejected outright.

This has been a hotly debated issue. It has gone through the original stakeholder process. It involved Calpine and Seminole, of course, because of our current contract. It involved FMPA. It also involved the stakeholders, the stakeholder process. It was then later part of a series of FERC filings.

There were three separate filings. The applicants in all three of those filings committed to the December 15th, 2000, date, and the idea that the facilities constructed thereafter would be new facilities and not subject to pancaking.

CHAIRMAN JABER: Is there -- that Seminole/Calpine example has come up several times now. Is there a way to move forward with just the Seminole/Calpine agreement that's eventually --

MR. REGNERY: Certainly. We have, in fact, asked for there to be a specific, a specific provision in our TSR, our transmission service, pardon me, our TSA, our transmission service agreement, requesting some or requesting Tampa Electric to give us a right under that contract to alleviate any pancaking that would be associated with that. And the fact that we would be able to reduce any transmission service that we as Calpine take under that agreement and that in the future then Seminole would be able to take it as a network resource across GridFlorida once GridFlorida goes into operation without any further studies and without any further costs or upgrades associated because they would have already been built as a process of our transmission service agreement being entered.

CHAIRMAN JABER: So you are pursuing those discussions then?

MR. REGNERY: Yes, we are. This is an, this is an absolute vital position associated with Calpine and its contract with Seminole and Seminole's position with respect to its purchase, its current purchase of megawatts out of our Osprey Power Plant.

The ironic thing about this is that, is that the change proposed by the applicants is exactly the gaming that they told FERC they wouldn't engage, that they were trying to prevent and didn't want other people engaging in.

On December 15th they inserted or responded to a FERC filing to say that the whole reason for putting the December 15th, 2000, date in was to avoid there being a gaming or a mad rush for, pardon me, a gaming and having there be a situation where people could decide whether or not they wanted a grandfathered contract or a non-grandfathered contract depending on when the date GridFlorida came in. So they set an arbitrary date, which then everyone relied upon in the context of what were going to be new facilities and not pancaked.

And now they've changed the date and engaged exactly in the gaming that they prescribed they were going to prevent. It's simply a money grab, that's the only thing that we can see it as. But alluded to -- this is absolutely, positively a money grab with respect to grandfathered transmission revenues, nothing else.

The most upsetting thing --

COMMISSIONER DEASON: Excuse me just a moment. In something you just said there, I need some explanation.

When you use the term "money grab," how does that relate to how FERC sets the rates? I mean, I was under the impression that it's a regulated monopoly and in the long-term you're not going to have a money grab because you're going to have a rate base and you're going to have a rate of return and FERC is going to monitor that and set the rates accordingly. So how do you reconcile the term "money grab" with the way I envision the regulation that goes on by FERC? And maybe I misunderstand how FERC regulates.

MR. REGNERY: Yeah. I think what it is, Commissioner, is that as of December 15th everything that was supposed to be built after that date under, and any transmission service agreements that were entered into after that date, the, the revenues associated with that once GridFlorida goes into operation would be converted over to a new contract under GridFlorida so that it would be converted to a postage stamp rate.

COMMISSIONER DEASON: Uh-huh.

MR. REGNERY: Okay? So the contractual expenditures under that, under that, under that transmission service agreement would no longer exist and the network customer then would come in and use his network service to get access to that generation, to that transmission. He would use his -- so he would be using, he would be paying a postage stamp rate and pancaking. By pancaking across TECO and then FPL to Seminole, that cross TECO would be discontinued. It would just be one postage stamp rate going to GridFlorida. And that was the understanding that was represented to us. Okay.

We, we located and chose to build our power plant and move forward with siting processes, and Seminole bought megawatts from us under the assumption that that's what it was, that there would not be this pancaking rate continuing on afterwards.

COMMISSIONER DEASON: See, I understand all of that. I guess I'm trying to understand -- money grab to me is an undue enrichment. How is there an undue enrichment?

MR. REGNERY: Well, the representation to us was there would be no pancaked rate, there would be no wheel paid to TECO once GridFlorida went into effect because this was a post December 15th, 2000, contract. So now --

COMMISSIONER DEASON: Now you may end up paying more, but does that mean somebody else ends up paying less? I understand your concern that you may end up paying more. But the reciprocal of that is someone else would end up paying less, which means no undue enrichment.

MR. REGNERY: No. The money actually would be a transmission wholesale revenue that would go directly to TECO.

COMMISSIONER DEASON: It would go directly to TECO and, therefore, in your opinion, that's, that's undue enrichment?

MR. REGNERY: Correct.

COMMISSIONER DEASON: Okay.

MR. REGNERY: Because that was contrary to the representation that they made to us associated with our, when they used the December 15th, 2000, date, the decision that we made to locate our power plant, we decided to locate it and go through the siting process associated with it.

COMMISSIONER DEASON: Okay. I'm just trying to understand. Thank you.

MR. REGNERY: And that's pretty much all I wanted to contribute this afternoon. So thank you very much.

CHAIRMAN JABER: Well, thank you. Ms. Paugh, who is next?

MS. PAUGH: I'm sorry?

COMMISSIONER JABER: Who did you have next on your list?

MS. PAUGH: We're finished. I did want to thank you for your indulgence in our market site discussion and request that continuing discussions on this very important and very complex topic be considered for a collaborative process. I think it lends itself better to that than perhaps evidentiary proceeding, or take an evidentiary proceeding and have more of a dialogue. But we do encourage the Commission to continue with this process and to continue to evaluate it very carefully. Thank you.

CHAIRMAN JABER: Mr. McGlothlin, you had something to say?

MR. McGLOTHLIN: Yes. Just to echo that and add a remark or two. And partly in response to Commissioner Deason, who observed that we were trying to pool a lot of information at the Commissioners in a short amount of time. That's a function of a couple of things, Commissioners.

Obviously the market design is of critical importance to us and to other stakeholders. It is highly technical, it is fact-intensive, and more than any other aspect that I can see in the GridFlorida application it's disputed, so you have significant disputes of factual matters calling for the application of technical expertise before you can make any informed judgments as to, as to which of the competing arguments should, should proceed.

And so with that in mind, it's our belief that this should not be the end of the presentations, that it would benefit the Commission and would serve the rights of affected parties to have a process, whether you call it a collaborative or an evidentiary proceeding or a combination of both, that gives this, this subject matter the importance it deserves. Thank you.

CHAIRMAN JABER: Thank you. Okay. Next on my list we've got FIPUG.

MR. PERRY: Good afternoon, Madam Chairman, Commissioners. My name is Timothy Perry. I'm here on behalf of the Florida Industrial Power Users Group. I'm just going to make my comments very brief.

FIPUG supports wholesale competition in Florida. A robust and competitive wholesale market inures to the benefit of Florida's retail customers through lower rates.

FIPUG also supports the RTO concept. The RTO concept holds the promise of facilitating a more robust and competitive wholesale market in Florida, and thus also holds a promise for lower rates for Florida's retail ratepayers.

FIPUG has filed comments in this proceeding earlier and we feel that these comments speak for themselves and we'd like to stand on those comments.

To those comments I have nothing further to add today. If you have any questions based on those comments, feel free to ask me; otherwise, that concludes my presentation.

CHAIRMAN JABER: Okay. Thank you, Mr. Perry.

Public Counsel?

MR. HOWE: Chairman Jaber, I have no comments to make, unless you have questions on the written comments we filed.

CHAIRMAN JABER: Not right now.

And Trans-Elect.

MS. FUTCH: Madam Chairman and Commissioners, my name is Natalie Futch from the law firm of Katz, Kutter, Alderman, Bryant & Yon on behalf of Trans-Elect. Bernie Schroeder, who is the president of Trans-Elect and who many of you have heard speak elsewhere, will make brief comments in support of Trans-Elect's filing and related specifically to the issue of not-for-profit versus for-profit.

Al Statman, who is the executive vice-president and general counsel of Trans-Elect, is here to my left as well today.

Very briefly, Trans-Elect was started in 1999 and it is the first and only truly independent transmission company in North America. Its goal is to establish a network of independent transmission companies.

Trans-Elect recently finalized the purchase of Consumers Energy Company's transmission system in Michigan known as the Michigan Electric Transmission Company. It is a general partner in a consortium that form AltaLink to acquire the Trans-Alta Transmission System in Calgary, Alberta. Trans-Elect was also selected to participate in the partnership along with other public and private entities to build the expansion of the Path 15 transmission bottleneck in Central California.

Essentially, as Trans-Elect stated in its filing, it supports the GridFlorida company's compliance filing. Trans-Elect is here because it believes that the compliance filing complies with the December 20th order, but it urges the Commission to maintain the flexibility that is included in the GridFlorida formation documents to preserve the option of a for-profit independent transmission company model in the future.

Bernie Schroeder will provide further comments regarding Trans-Elect and its interest in this docket. Thank you.

MR. SHROADER: Thank you, Natalie, and thank you, Madam Chairman and members of the Commission, for having us down to Florida today. I've met with each of you before and, of course, we participated in the FERC infrastructure conference just several weeks ago. I, by reason of knee surgery, could not attend that conference, but we were ably represented by Al Statman, who, as Natalie said, is with me today. If you were there, you also heard Chairman Pat Wood of the Federal Energy Regulatory Commission praise our efforts in independent transmission and that we present a model that ought to be carefully looked at.

Further, Ed Tarillo of Berenson, Minella (phonetic) in New York City mentioned how the investment community is reacting very positively to the Trans-Elect model.

Natalie has pointed out our recent accomplishments. In addition, we are under a confidentiality contract with four companies in the midwest, two in the south and two in the west, so we hope to grow quite rapidly here in our efforts.

We are a member of the only FERC authorized RTO, which is the MISO in our Michigan property, which is also a peninsula, I would point out. We have joined the MISO there. And, indeed, our senior vice-president for transmission systems operations is one of the architects of that RTO.

As Natalie also said, we support the GridFlorida filing, and we certainly commend Mike Naeve, an old friend of mine, in his eloquent efforts to explain that this morning. We think that the companies are on the right track here and moving down the right path to present to this Commission and to the FERC a model which can, can really, really work.

We also support, of course, the idea of, of a not-for-profit oversight entity. Whether we call that an RTO or an ISO, it is a mechanism under which we, as a for-profit independent transmission company, are most willing to work. In fact, we're quite willing to do it either way. We would -- had GridFlorida -- you know, where you stand depends on where you sit. But had GridFlorida said they wanted a for-profit ISO, we thought that we could have fit in and fulfilled that, that role. But as a not-for-profit ISO we're perfectly comfortable serving under such an oversight entity and, indeed, there are various different obligations, rights and duties for both the ISO and an independent transmission company under that ISO.

Well, why would you do that? The reason is there is a lot of talk today about market participants, market power, and not a lot of talk about investment in transmission itself over time.

Trans-Elect, as an independent transmission company, we think, solves all those problems. We are only in the transmission business, we'll only ever be in the transmission business, and the only thing we ever want to own, operate or invest in is transmission. We are not market participants and we have no market power.

We believe that we, we have a solution to the three major points that we thought that this Commission raised in its November order; that being the need for independence, the need to not divest assets in Florida at this time, and the prospect of eventual participation in a larger RTO, perhaps even larger than the State of Florida itself.

We requested this time and requested in our docket to be participants in the ongoing process here, which we think is very enlightened and includes all of the necessary parties. We think we bring a perspective and an idea to the table which the citizens of Florida could benefit and we have worked with commissions around the country. We invite you, of course, to talk to those commissions and how we work out our various plans and pricing and so on.

Again, transmission is our only focus, and we have access to the financial markets, access to capital to invest in that transmission. Florida is one of the most rapidly growing states in the country, as you know, and investment in transmission is going to be a long-standing concern of the people here.

Transmission operations, we have over 12,600 miles of line. Now we're involved in over $850 million worth of assets, and we believe very strongly that we could run the system exactly the way the people of the State of Florida want and do it in a way that satisfies both this Commission and another commission up on the Potomac River.

Again, we ask for flexibility from this Commission on the development of the process here. I don't want to in any way imply that we have any agreement with any of the GridFlorida companies. We have talked and we hope to continue to talk, but we merely present an alternative idea that we'd like to have considered over time. We thank you for your invitation here. And since we're the last ones, we will be blessedly brief unless you have questions you want to ask us.

CHAIRMAN JABER: What's the alternative idea you would present over time?

MR. SCHROEDER: Well, I think the idea under the November order is to have an independent transmission operator who also has a stake in the system, an ownership position of, say, 10 to 20 percent, where the incumbent utilities hang on to the majority of the system but as a passive owner and let an independent company actually run the system and be the participant underneath the ISO that you've heard explained here.

CHAIRMAN JABER: So there would be no change of ownership?

MR. SCHROEDER: Not -- no, there wouldn't, not a majority ownership, but you would have an independent operator.

CHAIRMAN JABER: There would be some sort of delegation of control?

MR. SCHROEDER: Yes. The delegation of control and the operation of the system itself would be delegated to Trans-Elect. The incumbent utilities would retain whatever passive ownership position that they have; of course, always able to call back what it is they've sold to us if that were an alternative down the road.

CHAIRMAN JABER: How would you all be funded?

MR. SCHROEDER: We raise our money from the capital markets in New York primarily. GE Capital was our big financial partner in the Michigan deal. The MacQuarie Fund, which is an Australian bank, was our financial partner, along with the Ontario Teachers Pension Fund in the acquisition in Calgary.

We have found that there's a big appetite for hard assets in the post-Enron and the post-California problems, and we represent that, that kind of an investment. We've identified literally hundreds of millions of dollars.

CHAIRMAN JABER: That's how you receive your capital funding. But in terms of day-to-day operations of Trans-Elect, how are you, how do your shareholders get a return on their investment? Do you collect fees from the participating transmission?

MR. SCHROEDER: We would operate -- there's several ways to do it. There's several ways that we make money. One is by the collection of a fee. The other is whatever ownership share we have, those revenues do come to us. And then through efficiencies in the system, which we as an independent transmission only company can, can provide, that's the way we make money over time.

Our goal in, in most areas where we are is to own 100 percent of the transmission; therefore, run it just like independent companies. Here because of the December order that the FPSC put out, divesting is not something that you want to have happen. So we concocted this idea as a way to, to keep the ownership here but to have independent operations.

I would say by way of investment that if we owned 20 percent of the investment in Florida, that would be larger than the 100 percent of the investment we own in Michigan. So it's still a very significant system and our investors would be very happy with that indeed.

CHAIRMAN JABER: Something you said I didn't understand. You said you can make money also off of how efficient you run the transmission system. I didn't understand that.

MR. SCHROEDER: Well, wherever we go, the transmission owners in every state and every region say they have the best run transmission system in the country. At the same time our transmission guru, Paul McCoy, says he can increase that efficiency by X percent, often 10 percent.

I finally asked Paul how, how that was possible. And he said, well, it's just really a question of focus. When all you own is the transmission and all you focus on is the transmission and you don't have loadings from other, other items -- and if you can use a hypothetical capital structure, for example, at the FERC when we, when we reorganize, there are efficiencies in the system that you can get because that's all that, that they do. And I don't mean to imply in any way that the companies aren't running a good system. It's just that if that's all you do, you can eke out, and indeed it's in your interest to eke out efficiencies in the system so that you can, you can keep that margin.

CHAIRMAN JABER: But you won't own any of the assets. I guess I need to --

MR. SCHROEDER: Well, we'd own, we would own, say, 10 or 20 percent. You want, you want the independent operator -- if we were just the operator, then we would just earn a fee. But you want -- I would think you would want the operator of that system to also be an investor, to have a stake in the system. And in that portion of it is where we would make those efficiencies happen.

CHAIRMAN JABER: Okay. So you envision as the operator of the system you would also be able to construct new lines and invest --

MR. SCHROEDER: Yes. Absolutely. That's what we, we want to do. We want to invest in new line. And if we owned an undivided interest in the systems that exist and then constructed new lines at the direction of this Commission or whoever thought those lines were prudent and needed, then we would, we would increase that undivided interest by that margin.

I think that if you are, if you are an integrated utility, you have various areas where you can invest and you have to make a decision which is the most efficient and which is the best return for your shareholders. In Trans-Elect we only have one place to invest, and that's in transmission.

COMMISSIONER DEASON: Even if you do not have an ownership share, couldn't your fee structure be based upon some type of incentive so that you have the incentive to, to find and, find efficiencies and implement those efficiencies?

MR. SCHROEDER: Yes. Yes.

COMMISSIONER DEASON: Another question. If you acquire an ownership interest in existing transmission facilities, does that make you a regulated utility?

MR. SCHROEDER: Under, under Florida law?

COMMISSIONER DEASON: Yes.

MR. SCHROEDER: That's an interesting question. And I'm not sure about that, so I'm going to ask counsel.

COMMISSIONER DEASON: And I'm not meaning to put Natalie on the spot. And if we need time to analyze that,

that's fine.

CHAIRMAN JABER: We'll have post-workshop conferences.

MS. FUTCH: We've done some preliminary research into that issue especially related to whether Trans-Elect would be a utility under the Transmission Line Siting Act. Honestly, we think that under the planning protocol and the formation documents perhaps you could use the participating owners, even if they had the small percentage ownership, perhaps you could use an existing Florida utility's eminent domain authority to expand existing transmission lines or construct transmission lines.

However, it's possible, as another member of our firm, new member of our firm, Billy Styles, may add that a change in the law may be required in order for Trans-Elect to have authority under the Transmission Line Siting Act.

But to answer your question, short answer to your question, we believe that, no, Trans-Elect would not be a regulated utility under Florida statutes.

CHAIRMAN JABER: All right. Mr. Shroader, did that conclude your comments?

MR. SCHROEDER: Yes, it does. Thank you very much, Madam Chairman, members of the Commission.

CHAIRMAN JABER: Thank you. All right. We have response by the GridFlorida companies. But I think, Commissioners, it's appropriate to take a break until 4:00. We'll come back at 4:00.

(Recess taken.)

CHAIRMAN JABER: All right. Let's see. We're at the stage now with a response by the GridFlorida companies.

Mr. Naeve, I'm assuming that will be you.

MR. NAEVE: Yes, that will be me. Well, we heard a great deal today and probably more than we have time to even begin to respond to at this stage. So we will provide you obviously a more detailed response in written comments that we file.

There are three or four points, I think, that were made today that we felt important enough that we respond to them at this stage. The first set of comments dealt with the governance issues. One series of comments dealt with the Board Selection Committee. And first, people suggested again that the investor-owned utilities might have undue influence because they have three of the nine members of the Board Selection Committee.

I would add -- I would first point out that the Board Selection Committee that we previously filed had not three of nine members representing the investor-owned utilities but three of eight. That Board Selection Committee was described to this Commission, and it was also presented to FERC and FERC approved it. We have now added one more member so that the influence of the investor-owned utilities has been reduced. We think -- we don't think we have too much influence. We think we are underrepresented. We represent over 80 percent of the customers in Florida. We own over 84 percent of the assets. By any other -- any normal measure, I think one couldn't say that we're overrepresented on that committee. We also are the only entity on the committee that is regulated by this Commission. So to the extent that the entities that you regulate and have responsibility for are represented on that Board Selection Committee are represented by us.

Now, that does bring up one other issue, however, and that is, you inquired about what might be the role of the Public Service Commission in the Board Selection Committee. We had thought it important to add this extra seat to further water down the votes of the investor-owned utilities, and we had proposed that that extra seat be selected by the Advisory Committee. We are quite amenable to an alternative approach, that that Board -- that that seat be available to the Public Service Commission if that's a desire of yours. So let us know on that, and we're prepared to do that in lieu of having the Advisory Committee pick that seat. Each of the members of the Advisory Committee will be represented -- or each of the groups in the Advisory Committee will have their representatives on that committee. So this would provide a guaranteed assured slot for the Public Service Commission.

Likewise, with respect to representation on the Advisory Committee, we are prepared to make an adjustment to the Advisory Committee. If you so choose to have a guaranteed slot on the Advisory Committee, we would be happy to accommodate that as well.

With respect to open meetings -- oh, one other point I'd like to make on the Board Selection Committee. It has been important to us all along to have an independent set of directors that run this new enterprise. We saw what happened in California. We've seen -- we've been apprehensive about having stakeholders run the process, or market participants. Each of these market participants will have their own stake in the game, and we wanted the enterprise to be run by people who do not have a stake in the game.

So throughout this whole process, we have been trying to promote features that provide for the independence of the Board. And we have been fighting back features that give the stakeholders too great a stake in the policies of the Commission. We want input from the stakeholders. We think it's very important that we receive it; that the Board be informed and knowledgeable about what the stakeholders want, but ultimately, we don't want the Board accountable to the stakeholders. We want the Board to feel independent and free to make their own decisions.

Commissioner Deason pointed out that if we had the

Advisory Committee, that is, the group that gives advice to the Board, also be responsible for picking the Board and for dislodging Board members, that that might somehow change the relationship between the Advisory Committee and the Board, and quite frankly, that is a factor we have discussed with the stakeholders. We've expressed that very same view, and it's a concern of ours as well.

With respect to open meetings --

CHAIRMAN JABER: Well, before you leave that, you said if there are suggestions or changes, you'd be amenable to considering them. I keep coming back to the assertion that the Board -- the Selection Committee Board is heavily weighted toward the IOUs, and I think that argument stems from the fact that you've gone sort of from one IOU representative to three.

MR. NAEVE: Well, we've gone from -- we've always had three.

CHAIRMAN JABER: Did you? Okay.

MR. NAEVE: No, we used to have three of eight. We've now gone to three of nine.

CHAIRMAN JABER: Okay.

MR. NAEVE: And FERC approved it when it was three of eight. The proposal we submitted to you last time had three assured seats for the IOUs. So the numbers really haven't changed. They've perhaps become more favorable with respect to reducing their representation.

CHAIRMAN JABER: Okay. You've just added that last seat for the Advisory Committee to make a suggestion.

MR. NAEVE: Yes, because people were complaining that perhaps we -- the investor-owned utilities had too many seats, and so to give them a somewhat diluted voting power, we added yet another seat. There is a distinction (phonetic), though, about it becoming too great a -- too large a committee.

CHAIRMAN JABER: Since the Advisory Committee is represented -- is representative of all of the IOUs though, would you consider taking the three representatives in the Board Selection Committee down to one? You don't have to answer today. It's something to think about.

MR. NAEVE: Okay. I frankly think given the size of the population represented by and served by those three investor-owned utilities, I would think that this Commission would want them represented on that committee. It kind of depends on how you decide what's fair representation. The Advisory Committee kind of is based on the assumption that one entity, one vote. So an entity that serves a million customers will get the same vote as an entity that serves 15 customers. And that may be one fair way to look at it, but there are other ways to look at it too.

Another way to look at it is that your votes are weighted somehow by the amount you have at risk and at stake. And frankly, for the most part, the way the governance is structured, your -- the first approach is taken one entity, one vote. In this case, the investor-owned utilities are given three votes out of nine, but that is actually somewhat small relative to the size of their investment in the state and their -- and the numbers of customers that they serve. And quite frankly, this issue was raised before FERC, where parties suggested that because of the disproportionate voting of the investor-owned utilities, they might have undue influence and therefore cause the RTO not to be independent. And the Commission considered that evaluation -- or that assertion and decided that three out of eight wasn't enough that they could have that kind of influence.

CHAIRMAN JABER: I guess I keep coming back to, though, Mr. Naeve, one of my ongoing questions relates to, is it -- from a regulatory standpoint, should I be caring about the makeup of the Advisory Committee in terms of making sure the IOUs are well represented there because they've got so much of the transmission responsibility? And if we had to find places for consensus, maybe the consensus is on the Board Selection Committee. You know, which committee needs to have more IOU representation, and which committee needs to have more governmental entity representation?

MR. NAEVE: Yeah, I frankly think from the perspective of the investor-owned utilities, getting the Board right is the most important thing. You want high quality, solid individuals on that Board.

With respect to the Advisory Committee, that too is extremely important, and they will have their voice on that but it is advisory. And hopefully this process will be open enough and broad enough that your -- you won't be ignored if you're not on the Advisory Committee. We have a very open process; a very participatory process, and we invite everybody into the process, not just the Advisory Committee.

The Advisory Committee is guaranteed certain things, but the whole structure of this RTO is developed in a way that everybody is invited into the tent, and everybody has an opportunity to get their two cents in. So I think from the perspective of the investor-owned utilities, if they had -- could have one more seat on the Advisory Committee or one more seat on the Board Selection Committee, they would choose the Board Selection Committee because that -- it's important that you have high quality Board members.

COMMISSIONER DEASON: Let me ask a question. Review for me the other five slots in the Board Selection Committee. How are they defined?

MR. NAEVE: Well, there is one slot for each of the stakeholder groups. And I'd have to turn to the bylaws to come up with a list of the stakeholder groups, but there's essentially -- well, let me find the definition. It will take -- actually, I don't have it with me. Do you have it there, John?

One for generators, one for marketers, one for TDUs that serve load, I think another for TDUs that serve wholesale load, one for governmental entities, and non-profits. I think that's the list basically. Is that a fair description?

CHAIRMAN JABER: That's six.

MR. NAEVE: And then we'll create on the -- that's the Advisory Committee -- or the Advisory Committee each of the -- and then one for investor-owned utilities on the Advisory Committee, so each of them have two seats on the Advisory Committee. Those are the stakeholder groups.

On the Board Selection Committee, you have the three investor-owned utilities; then you have one representative from each of those stakeholder groups, and then you have an at-large representative which we had suggested could be from this Commission.

COMMISSIONER DEASON: And there were two slots for TDUs, one serving -- could you clarify that again?

MR. NAEVE: Yes. We have, you know, different types of TDUs in the state and, for that matter, throughout the United States. You have TDUs that are largely just load-serving entities, distribution companies, that don't have transmission assets. Then you have TDUs like -- more like Seminole or FMPA that provide wholesale service to other TDUs. So we have one seat for each of those.

COMMISSIONER DEASON: And what happens if, for example, generators, they seem to kind of speak with one voice most of the time, but what if they disagree as to who should be the generator representative? Who resolves that dispute?

For example, say, Generator X has one viewpoint, and Generator Y has another viewpoint, and they can't agree as who they want on the Selection Board.

MR. NAEVE: Well, there's -- I need to discuss that two different ways. One way for the Board Selection Committee and the second way for the Advisory Committee.

COMMISSIONER DEASON: Okay.

MR. NAEVE: In dealing with the Advisory Committee, the -- each stakeholder group will develop its own rules and procedures. The generators will meet as a stakeholder group. That stakeholder group will elect their representatives to the Advisory Committee and will elect their representatives to the Board Selection Committee. And, you know, I assume in the generator group there might be, hypothetically, 15 or 20 members, and they will have an election, and choose -- by whatever rules they develop themselves that they want to follow, they will choose their representatives. So I presume if there is a deadlock on who they choose, they will have to develop a process in their group for resolving that deadlock. Then -- so that determines how members are selected.

Now, how they conduct their business, let's talk about that. In the Advisory Committee, it's composed of two representatives from each of these groups. And the Advisory Committee will provide -- it's the direct contact between the stakeholder groups and the staff of the RTO and also the Board of the RTO. Representatives of the Advisory Committee will attend every RTO Board meeting. It's a public meeting, a decision-making meeting. And they're guaranteed the opportunity to present -- to have a representative present the view of the Advisory Committee and also to have a representative present the view of a minority opinion.

Now, we -- a number of the participants in the Advisory Committee say that anybody -- that they should be permitted to present as many minority views as they choose. And my expectation is, the Board will probably want to hear as many minority views as the Advisory Committee may present to them as long as it doesn't get it out of hand. But we don't want to trivialize the role or marginalize the role of the Advisory Committee, and we don't want to tie the hands of the Board too much in deciding how they're going to conduct their business.

We have said that each -- that the -- each -- that the Advisory Committee can present its views and minority -- a minority view at every Board meeting. That's a guaranteed right. We call it a -- you know, the bill of rights for the Advisory Committee. And if there are other views that are held by different members of the Advisory Committee, there's nothing that precludes the Board from hearing those views, and I expect they would want to hear them. But if this becomes too tedious where every Board meeting becomes nothing but an eight- or ten-hour session of every stakeholder wanting to come up and offer its alternative view --

COMMISSIONER DEASON: Like a PSC hearing; right?

MR. NAEVE: Right.

(Laughter.)

MR. NAEVE: We want the Board to have some flexibility on how it decides to conduct its business, so we've left it that flexibility, but we provide a guaranteed right that they're going to hear at least the primary view of the Advisory Committee and the majority minority view. And if they want to hear more, they're certainly free to do it, and we expect they will, again, unless it becomes out of hand.

COMMISSIONER DEASON: Thank you.

MR. NAEVE: Now, with respect to how the elected representatives to the stakeholder -- I'm sorry, to the Board Selection Committee will conduct themselves, that's a much different process. That's a process where it has to be conducted in a way that respects the confidentiality of the parties that are being considered for Board members. And again, we've already been down this road one time.

We've interviewed a number of -- well, we actually --

we had a number of perspective candidates identified for us, and we interviewed one of them, a very prestigious and competent individual, who did not want to be identified. And we were told by our headhunting firm that most would choose not to be identified. So that committee has to be a fairly tightknit group. They have to work out among themselves confidentiality agreements where they will not disclose the names of the individuals that are being considered, and we're going to have to trust that committee to make some recommendations on Board seats. But there will be restrictions on their ability to disclose to the outside world who the potential candidates are. But again, if we want that process to work, that's a set of restrictions, I think, that we have to live with.

Okay. With respect to open meetings, again, I think we have tried to balance the effectiveness of the Board with openness and public access, and I think we've provided an incredible amount of public access. I described earlier a significant amount of that access. We also have an incredibly broad information policy that requires documents and information held by the RTO to be made available to the public. But on the flip side, we want it to be effective. And we want Board members to feel free to talk to each other, to raise complaints with two or three of the Board members against the chairman or others and to call each other and encourage that kind of dialogue. We think it's very important for the Board to be effective and for there to be divergent opinions raised to the top.

CHAIRMAN JABER: Wouldn't that require decisions to be made?

MR. NAEVE: I'm sorry?

CHAIRMAN JABER: Wouldn't that require decisions to be made?

MR. NAEVE: No. I think to the extent that a Board member wants to raise something at tomorrow's meeting or the meeting after that and they call a couple other Board members and try to explain to them what they're going to do and why they're going to do it, I think that's fine. When they go to the meeting, they're going to have to, in the public, have their discussion among all the Board members, explain what they're doing, and they'll have to provide to the public all documents that they provide to the other Board members. And it's going to be an open and full session. We just simply want Board members to be free to be educated, to act in small groups or to have discussions in small groups so that they have the benefit of open and free dialogue among themselves. We think that will lead to much better decisions.

I can just tell you from my personal experience, having been on a commission where we had very tough standards and not being able to talk to each other, it was very difficult and inefficient in the way we had to try to conduct our meetings. We've tried to compromise and say, if you're going to make decisions, you do it in the public. And in light of that, we are going to propose a couple of changes because we realize we hadn't fully addressed some of the concerns.

We had allowed committees to be delegated the power to make decisions, and we need to change our rules to say, when they are making decisions, when power has been delegated to them, that has to be in the Sunshine, they have to make those decisions in the public. And then secondly, we had also permitted the Board to act through written consent, written action. We also realized that could have been used as a way to circumvent the Sunshine requirements for making decisions, and we're going to change that as well and not allow them to act by written consent. They have to act in the public -- in public meetings.

The -- a number of the munis and other governmental agencies pointed out that they live with Sunshine rules. I think there's a couple important distinctions, though, and that is, their Sunshine is their regulation. They are not subject to regulation. This entity is going to be subject to extensive regulation. And we have a very broad Sunshine here and regulation on top of that.

And then secondly, every decision that is made by this group, every major decision, will have to be filed at

FERC, maybe filed with this Commission, and go through another process that is a public process to review that decision. So it's not like we're going to have decisions that are made that affect everybody and that's the end of it. This is going to be a very open and participatory process, and then also it's going to be subject to regulatory oversight.

With respect to a few other issues, let me talk briefly --

CHAIRMAN JABER: One of the things that Mr. Bryant said on this point that I thought was very good, he conceded that there will be some necessity for having closed meetings, but there should be an outline or at least some sort of guidance on even examples of when those circumstances will occur. Does your --

MR. NAEVE: We will look at trying to come up with a definitive list for what might be considered at closed meetings.

CHAIRMAN JABER: Thank you.

MR. NAEVE: On market design, we heard a great deal today on market design, more than I could possibly comprehend much less respond to at this short time. I'd like to make a couple of points, though, that we heard. First, how does one allocate rights to use the transmission system? This is an important issue, and this issue really is relevant whether you use a financial model or a physical model. You're going to have financial rights or physical rights. What do you do with them? How do you allocate them in the first place?

And the suggestion we heard today was that you not allocate them to historic users in proportion to -- or in relation to what they need to meet their current load and their future load, but instead you just have an auction. That's what the generation coalition proposed.

At the same time, you heard from a lot of other parties, the munis, the co-ops and everybody else saying, we don't want any surprises on congestion costs. We want rights to use the transmission system related to our load so that whereas in the past we've not had congestion costs, we suddenly don't incur them. As someone said, we want no surprises.

We had proposed for the physical model that we have an allocation process that is based on historic use, that you allocate the rights to the transmission system based on historic use, and I think that's a model that will produce no surprises. That was our expectation and our hope.

There was a suggestion that if you do that, the recipients of those transmission rights will have no incentive to make them available to other parties when they're not using them, and there also was a suggestion that they might be able to physically withhold transmission rights from the system. And I'd like to respond to both of those.

First, I think if you're allocated a valuable right and you are not going to need it, I think you have a significant financial incentive to try to capitalize on that valuable asset that would otherwise whither away. And indeed, under the proposal we've made, if you do not schedule that right, the right is allocated to third parties, and the -- or auctioned to third parties, and the proceeds for the auction don't go to you. So you have a strong incentive to auction it yourself and collect the proceeds rather than let the RTO auction it because you failed to schedule it or you failed to sell it to somebody else.

And then on the withholding point, that very same provision also addresses withholding. You can't withhold it. If you're not going to use it, then it's going to be auctioned off by the RTO.

With respect --

COMMISSIONER DEASON: Let me ask a question on that. If you're allocated the right and you don't use it under your procedure, it would be auctioned off, and the benefit would not flow to the owner of the right. You either use it or lose it.

MR. NAEVE: That's right.

COMMISSIONER DEASON: Okay. Does that give an incentive for the holder of the right to use it regardless even though it may not be the most economic transaction?

MR. NAEVE: No, I don't think because if your most economic dispatch causes you to not use that system and it has a value, you're better off selling it and capturing that value and dispatching your generation in the most economic way. It would be kind of foolish to dispatch your generation in an uneconomic way so that you use that transmission right and then give up the value that you would get from selling it at the same time. So kind of -- you're a double loser if you do that.

COMMISSIONER DEASON: So -- well, let me clarify. If you have it and you don't use it, you can sell it yourself. And if you don't sell it yourself, it's going to be auctioned off for you, and you don't get the benefit.

MR. NAEVE: That's right.

COMMISSIONER DEASON: Okay.

CHAIRMAN JABER: That's in your current modified proposal. That's not a change you're making today because of the comments.

MR. NAEVE: That's right. That's been there all along.

With respect to installed capacity, we heard a lot of people today say, we think it's important that there be some sort of capacity requirement, long-term planning capacity requirement, but we also think that this Commission has done a great job, and we should just -- we should have this Commission continue to do what it has been doing. We don't need an installed capacity requirement at the RTO level.

I guess we have a couple of observations relative to that. The people who are saying that to you are people who aren't regulated by you. So when you impose an installed capacity requirement, it's on other people, not on them, and frequently they can benefit from the surplus capacity that the others parties have without having to pay for it or incur similar costs themselves. So our view is, we certainly have not objected to having installed capacity requirements imposed on us. We think it's good for reliability. It assures that we meet the load of our state, and that's an important thing. We would just merely say that whatever rules are applied should be applied to everybody, not just to some people and let other people ride off their shoulders.

So our people proposal is one that would apply to all participants, not just to some participants. And furthermore, as to who sets the level, we've proposed the FRCC set the level of installed capacity, but if this Commission believes that it's more appropriate that they set the level, that's fine with us.

Finally -- well, there's a lot of other things. Let me talk about two other things, and I think that will be sufficient. With respect to planning, we learned a lot of things today. And one of the things we learned that was a surprise to us was that our original planning protocol was a widely accepted model by the stakeholders. We had -- it had been something that we had received a lot of complaints about when we prepared it. When we filed it at FERC, a lot of people intervened and said that it was not an effective model for a variety of reasons, many of the same reasons they now don't like the current model. But it was really quite a surprise to us that it was perceived as such a widely accepted model.

We also were surprised to hear that the new model is one which turns over control -- takes control away from the RTO and gives it to the participating owners. I have a copy of the planning protocol, and I would just read a couple of sections -- excerpts from it, and I have, frankly, a lot of excerpts I could read to you, but I'll just read a few of them. But the planning protocol were drafted to meet the FERC requirements that the RTO be in control of planning. And indeed, these planning protocol are based on the planning protocol already approved by the Commission for the Midwest ISO, but among other provisions it says, the transmission provider, meaning the RTO, shall be responsible for performing the planning function of the transmission system and shall serve as the point of contact for all market participants with respect to GridFlorida's transmission services and planning.

The transmission provider has the ultimate responsibility and authority for developing and approving the comprehensive GridFlorida-wide transmission plan through an annual process described herein. The planning function for GridFlorida shall be the responsibility for the transmission provider. In exercising such authority, the transmission provider shall receive one -- shall, one, receive, evaluate, and respond to requests for transmission service and, two, develop a comprehensive grid-wide Florida plan described as the GridFlorida plan.

The transmission provider shall make the final determinations in the process. The transmission provider shall be responsible for calculating ATC for the transmission system and so on. The transmission provider shall receive, evaluate, and respond to all requests for service. It shall analyze and make the determination on access on the transmission system and so forth.

It puts the responsibility in the RTO, not the hands of the participating owners. I think it's conceivable that there has been some language in here which may have caused some misapprehension about this point. It's certainly our intention that the RTO be in the driver's seat on planning, and we'll go back and look at it and see if there's changes that might clear up that apprehension.

I know in talking in the hallway with some of the people it was acknowledged that they simply didn't have a lot of time to look at this, and so it's my hope that they're kind of overreacting because they didn't have time to pick through it much like I think they probably overreacted to our first one, but --

CHAIRMAN JABER: Mr. Naeve?

MR. NAEVE: Yes.

CHAIRMAN JABER: The stakeholder process, I agree, you know, in the beginning worked well for the stakeholders. And having attended some of those collaboratives, I remember the dialogue going back and forth among all the stakeholders. I thought it was very effective. Would there be a benefit to scheduling -- you all taking the lead in scheduling a collaborative just on the planning document, even if it's just a walk-through the planning protocol with all the stakeholders?

MR. NAEVE: Oh, it's hard for me to say. I don't want to be thrown back in that brier patch, but it's a --

CHAIRMAN JABER: I think that sort of meeting, because the stakeholders acknowledge they didn't have a lot of time to digest the planning document, would be in order. You can do it. You've lived through the other --

MR. NAEVE: Oh, we can do it. It's a very time-consuming process, and it does -- frankly, we have over the -- over -- throughout this process, the stakeholder involvement has been very time-consuming for us but time-consuming for the stakeholders as well.

CHAIRMAN JABER: And quite effective.

MR. NAEVE: And I think we have a much better proposal because of it.

CHAIRMAN JABER: Right.

MR. NAEVE: We've got a lot of features which were not in our original feature, and indeed, every time we had a stakeholder meeting, we made changes. That's not to say that the stakeholders feel like they got everything they wanted. In fact, we didn't get everything we wanted. But -- and frankly, too, a lot of the stakeholder comments you hear here today other stakeholders would disagree with them. It's not, if we make a change for one stakeholder sometimes, it causes other stakeholders to -- it raises concerns with them. But it's been a good process. But at some point, you begin to hear a lot of the same comments again and again, and you realize you've come near the end of the process. I frankly think we are near the end of the process, although, you know, to the extent there are new documents, you know, there could be a --

CHAIRMAN JABER: I may not disagree with you that we're near the end of the process. Certainly that's been a goal of ours to see this to its finality. But to the degree the stakeholders have questions related to a specific item in the proposal, I think it's time well spent even if it's a conference call.

MR. NAEVE: Well, it's a suggestion we will act on.

I guess the only other thing I would say is, on the planning process we were also surprised that it didn't provide for collaboration and input from all parties. And I have, again, a series of quotes I could read you, but I think I won't labor -- belabor you with those points. They are in the protocol, but it was written with the intention that all parties be involved. That it be a broad, open collaborative process, and again, I think there may have been some misunderstandings as to that.

The only other point I will address, I believe, and -- I guess there are two more points. I have two more points, finally. One has to do with reliability. A number of parties have raised issues about reliability especially in rural areas where it is harder to provide identical reliability for customers as it is in major urban areas where you have -- you're much closer to generation and you're much closer to major transmission ties and redundant ties. But GridFlorida has -- the proposal has a number of features to address this issue.

One important feature is that we require the RTO to address each year the worst reliability situations, the delivery points where reliability is the lowest. That's been retained in our proposal. Secondly, we leave it up to GridFlorida to develop their planning standards for urban areas and rural areas. And to the extent that Seminoles and FMPAs and others believe that the standards aren't adequate for their areas, they're going to be in a position to make their points to the RTO. And then finally, to the extent that the RTO sets standards and a particular load-serving entity believes that they would like improved standards even beyond the ones that are identified by the RTO, we allow them to get improved facilities. They just have to agree to pay for those facilities themselves instead of shift the cost off to everybody else. So we have provided for improved reliability and I think in an appropriate way.

COMMISSIONER DEASON: So you believe that you've addressed Reedy Creek's concerns already?

MR. NAEVE: Reedy Creek's concerns are actually slightly different. They've -- I think with respect to some of the other reliability concerns we've heard, they really are in some ways cost-shifting concerns. We'd like beefed-up materials, and we'd like some of the beefed-up facilities, and we'd like those costs not paid for by us as enhanced facilities but rather paid for by everybody else.

I think in Reedy Creek's situation they are prepared to pay for enhanced facilities. They recognize that if they ask for facilities that are -- that exceed the standards identified by the RTO, they should pay for them. They take no dispute with that. They just are concerned that we may have modified the tariff in a way that doesn't allow them to do that and get those enhanced facilities, and also that we may have modified the tariff in a way that doesn't allow them to -- for expedited implementation on investment in facilities. And quite frankly, we think those provisions are essentially the same. The words may have changed, but we think they have exactly the same effect. So we're going to go back and look at our words and try to understand what their concern is because we thought we actually just kept exactly the same concepts in the revised planning document. We agree with them with respect to the substance, and it's just really a question of, does the language do what we think it does and what they think it does not do?

I think that summarizes our initial response, although we have -- you know, more detail we will provide you in writing.

CHAIRMAN JABER: You covered everything on my list except for one, Mr. Naeve. My notes from hearing the stakeholders, Reedy Creek did talk about the application of the functional test for the demarcation point. And I heard the suggestion or at least the concession that they would live with adding the word "transmission" into the definition of controlled facilities. And frankly, I thought we were done with the demarcation point issue as a result of our order, but apparently, you all have included some language in your --

MR. NAEVE: No, actually, we just -- our -- we thought our language was consistent with your order. And when the representative of Reedy Creek was here discussing that, I actually went back to your order to see if it was specifically targeted to just the facilities owned by the three sponsors or if it was targeted more broadly to all facilities. And quite frankly, reading the language, I have to say it wasn't clear. It could be read either way, but it certainly wasn't explicit --

CHAIRMAN JABER: Reading the language of our order? That was very clear.

MR. NAEVE: Well, actually, but I did think the language of the order was very persuasive as to why you'd want to have a clear demarcation. And you went on to say that we agree, a uniform demarcation is necessary to ensure equal access to all participants and to ensure that subsidies resulting from different demarcation points do not occur.

CHAIRMAN JABER: Well, it says, "Demarcation point for transmission facilities." So in your filing, did you --

MR. NAEVE: We just said if it's 69, it's transmission. We wanted a clear demarcation as opposed to having to look at every single facility and make a case for whether that particular facility is transmission or is not transmission. Quite frankly, in the stakeholder process, we heard from a lot of stakeholders who wanted a bright line, and they wanted a bright line for a lot of different reasons. And frankly, one of the reasons they wanted a bright line is they didn't want us excluding facilities saying that this particular facility is not covered by the RTO's control and open access tariff. Others wanted a bright line because they had 69 kV facilities that they wanted to be included because they got credits. They got -- it lowered their transmission rate by including their credits because they wouldn't have to pay for those facilities themselves. They would be shifted to the zonal rate. So this is an issue where people are all over the lot. And in our reply comments, we will give some thought to Reedy Creek, but I have to say it's an issue where if you make progress to assist Reedy Creek, then other stakeholders are going to stick up their heads and say, we're concerned about that.

CHAIRMAN JABER: Okay. But it's your position that you just included in the modified proposal what you believe to be consistent language with the order.

MR. NAEVE: That's correct.

CHAIRMAN JABER: All right.

MR. NAEVE: Actually, there is one other point which I was just reminded that was raised today. This is -- has to do with the changing of the date for what constitutes new facilities and what constitutes new contracts. And a suggestion was made repeatedly that the changing of the date had nothing to do with this process before this Commission. And I would just say that I think it had almost everything to do with the changing of the process before this Commission simply because we had established a date that was identical to the date that we had planned on putting the RTO in service, December 15th, 2000. And we were moving forward as fast as possible to meet that date, and I think that we very well could have met that date with respect to at least the initial implementation of the RTO. But this Commission decided that it wanted to take a look at the RTO before we went forward with it, and we put that process on hold, and consequently, the date was substantially delayed by virtue of the process before the Public Service Commission. And for that reason, we realized that the date we had targeted for implementation was no longer the effective date, and we put in another date that would be more closely tied to the actual implementation date.

CHAIRMAN JABER: Commissioners, do you have any follow-up, anything you want included in the post-workshop comments from today's workshop? Any questions to any of the stakeholders?

And Staff, I don't mean to leave you out of this process. Do you have any questions? Okay.

MR. KEATING: No. No questions, no.

CHAIRMAN JABER: Mr. Keating, you need to correct me if I'm wrong, but I have next in terms of critical dates for this proceeding, we have got post-workshop written comments due from all of the parties on June 21st. We have Staff's recommendation due to be filed July 25th. We have an agenda conference for August 6th.

IPPs, I heard your request with respect to an evidentiary process and ongoing dialogue. As far as I'm concerned, the dialogue is ongoing because the parties and Staff have had excellent communication thus far. I don't see why that's going to stop.

As a matter of fact, Ms. Bass, between comments and your Staff recommendation, I would expect that you have a meeting or two prior to filing the Staff recommendation. With respect to issues that require a hearing, it really just depends on your comments and the Staff recommendation. I don't think that's an issue we have to address today. I'm going to leave that up to legal counsel.

I guess I envisioned, and Commissioners, feel free to interject here, I envisioned to the degree we were dealing with a compliance filing and just addressing those very limited issues from the hearing we've already had, that those would be handled in a final fashion, and to the degree there are new topics raised here today or ones that you think of, I'll allow you all to let us know how to go forward.

MS. BASS: Okay. We can do that, and we will schedule a meeting after we get the post-workshop comments and prior to filing of the recommendation to see whether or not we've reached any more consensus and what the final issues are that need to be addressed.

CHAIRMAN JABER: To see how many issues you've reached consensus on.

MS. BASS: Correct.

COMMISSIONER DEASON: Let me see if I understand. The manner that -- the recommendation that will be brought to the Commission hopefully on August the 6th will be for final action of the Commission?

CHAIRMAN JABER: No. What I'm saying is, I think we don't know the answer to that until we see. I guess I always envisioned that some of them would be final action because we've already had a hearing, but I'd hate to make that decision today when we don't really know what is in front of us to vote on.

Legal, you agree with that?

MR. KEATING: That works for me.

CHAIRMAN JABER: Okay. Let me stop here and thank all the parties. This has been a very, very effective process. I know Staff has done a great job, but I also know all the stakeholders have done an outstanding job. Thank you very much. We'll see you soon.

(Workshop concluded at 4:46 p.m.)

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

We, LINDA BOLES, RPR, and TRICIA DeMARTE, Official Commission Reporters, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed under our direct supervision; and that this transcript constitutes a true transcription of our notes of said proceedings.

We FURTHER CERTIFY that we are not a relative, employee, attorney or counsel of any of the parties, nor are we a relative or employee of any of the parties' attorneys or counsel connected with the action, nor are we financially interested in the action.

DATED THIS 4th DAY OF JUNE, 2002.

Linda Boles

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