BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Numbers

SUPPLY MARGIN ASSESSMENT : PL02-8-000

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Rooms 2C
Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, D.C.

Tuesday, January 13, 2004

The above-entitled matter came on for technical conference, pursuant to notice, at 9:35 a.m.

BEFORE:

STEVE RODGERS (OMTR), presiding

APPEARANCES:

PANEL I:

JOE PACE, Director, LEGG, LLC

JOHN APPERSON, Director of Trading, PacifiCorp

JESSE TILTON, CEO of ElectriCities of NC

RICKY BITTLE, Vice President of Planning, Rates and Dispatching, Arkansas Electric Cooperative

RON McNAMARA, Vice President of Regulatory of Affairs and Chief Economist, MISO

STEVEN CORNELI, Directro of Regulatory Affairs, NRG Energy, Inc.

PANEL II:

BILL MARSHALL, Vice President of Fleet Operations and Trading, Southern Company

STEVE HENDERSON, Vice President, Charles River Associates

MICHAEL WROBLEWSKI, Assistant General Counsel for Policy Studies, Federal Trade Commission

BOB STIBOLT, Senior Vice President of Risk Management, Tractebel Corporation

GARY ACKERMAN, Executive Director, Western Power Trading Forum

DENISE GOULET, Senior Assistant Consumer Advocate, Pennsylvania Office of the Consumer Advocate

APPEARANCES CONTINUED:

PANEL III:

BILL HIERONYMUS, Vice President, Charles River Associates

BILL DUDLEY, Assistant General Counsel of Xcel Energy Services Inc.

PAT ALEXANDER, Energy Industry Advisor, Disckstein Shapiro Morin & Oshinsky

DON SIPE, Counsel with Preti Flaherty

ROBERT O'NEIL, General Counsel, Golden Spread Electric Cooperative

CRAIG ROACH, Partner, Boston Pacific Company

RODNEY FRAME, Managing Partner, Washington Office of Analysis Group

JOE PACE, Director, LECG, LLC

SEABRON ADAMSON, Director, Tabors, Caramoni & Associates

WILLIAM TOWNSEND, Senior Director of Database and Spatial, Platt's Energy Information and Trading Services

STEVE SCHLEIMER, Director of Market and Regulatory Affairs, Calpine Corp.

P R O C E E D I N G S

MR. RODGERS (presiding): Good morning. I lack the chairman's gavel this morning, but I'm going to try to bring the meeting to order anyway.

Good morning. Welcome to the FERC Supply Margin Assessment Technical Conference. This conference will address the following topics in four different panels:

First, how to define the relevant geographic market for purposes of measuring market power in the electric industry and how does transmission affect that delineation;

Second, proposed modification or alternatives to the Commission's SMA interim generation market power screen;

Third, what is the appropriate mitigation imposed on those that failed the screen;

And fourth, how can the Commission best address the data concerns associated with various market power screens.

This two-day conference will feature a number of respected panelists from many regions of the country and from very diverse industry and regulatory perspectives. Specifically, the group of panelists will include spokespersons for the three IOU's that were the subject of the Commission's earlier SMA order -- AEP, Southern Company, and Entergy.

Each panelist has been asked to speak for no more than seven minutes, after which time there will be an opportunity for Q and A from Commissioners or Commission staff before we move on to the next panelist.

Because there is significant overlap between the topics of each of these four panels, I've told the panelists that if there's time remaining in their seven minutes after they've addressed the topic of their panel, they may like to address the topics of the other panels. If they would like to address the topics of the other panels, they are free to do so.

After each panelist has spoken and after the Commissioners and staff have completed their Q and A, at the end of each panel there will be an opportunity for those in the audience to make comments or to ask questions of the panelists.

I would direct your attention to several microphones that are available at the bottom of each of the side aisles for this purpose.

I wish to stress that the focus of the conference is on the appropriate interim screen for a generation of market power.

And analysis of generation of market power is only one prong of the four-part test that the Commission has historically used to determine eligibility for electric market-based rates, with the other prongs being whether the applicant has transmission market power, whether there are other barriers to entry, and considerations related to affiliate abuse.

The Commission stated in the SMA order as well as in its December 19th notice of this conference that it intends to undertake a generic review of the methods that it uses for analyzing markets and market power and that it intends to launch a generic rule-making proceeding to address the various aspects of its electric market-based rate program.

I'd like to mention that we do have all four of our Commissioners in attendance this morning. Suedeen Kelly, Joe Kelliher, Chairman Wood, and Nora Brownell, we're pleased to have you all with us.

Let me also mention a few logistical matters. First, because there may be a significant line for lunch, if you'd like to save some time you can preorder lunch from the cafeteria in the building here. And I'm told that your lunch will be waiting for you at the time that you request.

Second, this conference is being transcribed. And a transcript of the conference will be available by the end of next week.

Finally, let me give a word of caution to our panelists. As you know or may suspect, staff spent considerable hours preparing the staff white paper for this conference that set forth staff's strawman ideas on these ideas.

While I recognize that there is some remote possibility that some panelists may disagree or quibble with a few of the staff's ideas in the white paper, please be aware that if your criticism becomes too personal or too aggressive, the panelists' seats are equipped with state of the art electric shock equipment.

(Laughter.)

MR. RODGERS: To my knowledge we've never had a reliability problem associated with the use of this equipment.

(Laughter.)

MR. RODGERS: With that our first panelist this morning is Dr. Joe Pace, who has been asked to appear by AEP. He is the director of LECG, LLC. Dr. Pace.

MORNING SESSION

MR. PACE: Good morning. I appreciate the opportunity to participate in these technical conference discussions.

By way of introduction I'm an economist and director of LECG, an economic consulting firm. Over the past 30 years I've testified many times before this Commission as well as before state regulators and federal and state courts on competition and market power issues.

In December 2001 I submitted an affidavit on behalf of AEP addressing the Commission's then proposed supply margin assessment, or SMA, interim screen analysis. The central theme of that piece is still the most significant point to make as we address the issues before us today.

That is, any market power screen analysis that ignores the applicant's native load and long-term contract obligations is fatally flawed. In my view no respectable intellectual case can be made for ignoring such load obligations, which indisputably affect any seller's ability to profit by withholding generation resources from the market.

And that's especially true when the screen analysis is or should be focused on a clearly defined three-year time horizon and when the inquiry can be reopened if material changes occur. Failing to recognize this cut the heart out of the SMA test. And any replacement screen analysis that makes the same mistake also would be fatally wounded.

I have provided copies here today of a prepared statement which discusses the proper role of market power screening analysis, addresses geographic market definition issues, and provides in my view an appropriate screen analysis to use in assessing applications for a market-based rate authority.

I welcome your questions on any of these topics, but I will confine my remaining oral comments to the geographic market definition questions posed for consideration by panel 1.

The first question inquires generally about relationships between transmission limits, geographic market definition and control areas. The conceptual relationship between geographic market definition and transmission is straightforward.

The absence of significant binding transmission constraints within an area generally means that the entire area should be treated as a single geographic market. In contrast the presence of binding transmission constraints between areas causes markets to separate, and thus defines boundaries between markets.

In principle therefore, the geographic market definition task consists of identifying the transmission limits that are likely to place binding constraints on market transactions.

The SMA screening analysis and all the alternatives discussed in the staff paper take a control area approach to defining geographic markets.

The general presumption is that the relevant geographic market encompasses all loads and resources within a single control area with notable exceptions, as I mention below, and that transmission limits between directly interconnected and inner control areas create potentially binding constraints on transactions among those areas.

The focus on control areas is practical since transfer limits traditionally have been defined and posted for transactions among control areas.

In my view this approach to geographic markets definition has been and remains a reasonable one. Of course, it will sometimes be appropriate to define an area smaller than a single controlled area as a separate market. This should be done when there is evidence that binding internal transmission constraints prevent the prospective purchasers in some subarea from being able to buy power from suppliers throughout the control area.

In fact, market power analysis conducted in the past has recognized the existence of significant internal constraints by examining subareas within the Cal ISO, ERCOT New York, and PJM control areas.

It is also true that relevant markets should be sometimes defined as encompassing more than one control area. This is the case when it can be shown that transmission limits between two control areas are not likely to place realistic constraints on transactions between those areas.

The next inquiry put to panel 1 concerns the treatment of load pockets. Load pockets by definition are areas bounded by transmission constraints that sometimes limit the ability to supply loads in the area to local generators. This ownership is likely to be concentrated. Market rules or contract obligations must be designed to prevent abuse of local market power in those cases.

Once adequate measures are in place to do this, there is no reason to conduct further separate analyses focused on those areas.

Third, the question of how transmission limits should be identified and measured. The objective of any solid market power analysis should be to identify realistic limits on competing supplies that can move into the market under study in response to attempts to raise prices there.

Normally two alternative measures of transmission capability would be amenable for consideration -- a measure of total transfer capability and a measure of available transfer capability.

In principle the extent of potential import competition in a particular market can be measured by starting with total transfer capability and subtracting capacity not usable by competing suppliers. One can total up all existing scheduled uses of import capability and add to that any remaining available transmission capacity.

In my opinion the most practical approach generally is to measure transmission limits by TTC's less any import capability not available to competitors as a result of the applicant's own use.

The problem with relying on ATC's as a measure of transmission capability is that import competition can be substantially understated unless the analyst can identify and include in the analysis all scheduled uses of the interface under consideration.

In my experience that has proven to be a very difficult undertaking. Without complete information, indeed reliance on ATC's can produce perverse results. For example, a fully booked transmission path will have no remaining ATC.

But this certainly does not indicate an absence of import competition. To the contrary, it indicates that the maximum amount of competing supply is already scheduled into the market in question.

I'll just mention briefly -- it's not a specific question, but also I would advocate that the transmission limit is used, the simultaneous limits, because to do otherwise is to deflect the reality of transactions that can take place in the market.

The next inquiry relates to how to account for competing supplies. I assume the question posed here is how to allocate any of the transmission import capabilities among the potential competing suppliers in interconnected market areas.

For example, if there were four suppliers in the first-tier control area each having 750 megawatts of uncommitted capacity, but only 2,000 of the 3,000 megawatts can be transmitted to the relevant destination market, what supplies do we include in the market calculations?

There are several responses. First, there is no need to attribute deliverable supplies to individual competing suppliers in order to calculate an applicant's market share or assess whether it is a pivotal supplier.

The only thing needed for this measure is the amount of total competition or competitive supply. You would only need to allocate shares to individual suppliers if you were using a test relying on HHIs.

However, if part of the uncommitted capacity in the first-year market is owned by the applicant, then the allocation of transfer capability from there to the relevant destination market can matter.

If you turned to our examples, if the applicant is one owner of 750 megawatts among committed capacity in the first-tier control area and if the allocating interface capability on a pro rata basis will attribute an additional

500 megawatts of supply to the applicant, add 1,500 megawatts of import capability to competing suppliers.

This pro ration may be acceptable for calculating uncommitted capacity market shares, but it is clearly inconsistent with the premise of the pivotal supply area analysis, which assumes total withholding by the applicant.

The applicant cannot withhold its capacity in the first-tier control area without releasing the transfer capability to competing suppliers to do more than fill it up. The pivotal suppliers' screen analysis therefore should assign the entire 2,000 megawatts in my example of deliverable capability to competitors.

The next question concerns, for this panel, how the screen analysis -- I can actually stop at this point in time. I've covered all but the last two questions.

MR. ROGERS: Go ahead.

MR. PACE: There are only two questions left. One concerns how do you deal with potential biases when the applicant itself calculates the transfer capability and administers the open access tariff.

I don't think there's any need to do anything special there. The short answer is that if the applicant is understating transfer capability, that will already show up in the market power analysis as a constraint on the amount of competition.

The final inquiry concerned what do you do when there are transmission-related constraints that limit output of particular generators.  Again the short answer to this is we want to measure commercial reality.  That should be the touchstone of any market analysis.

So if we have a generator that's got a 500-megawatt nameplate rating, but it can only do 300 megawatts because of the transmission constraints or for that matter because of limited water or other constraints, then we only want to include that in the analysis of the 300 megawatt level.

I'm sure I've exhausted my time.  I thank you for your attention.

MR. RODGERS:  Thank you, Dr. Pace.  We appreciate it.

Questions?

MR. PEDERSON:  One of the first questions I would have is in regard to actually historical trading patterns. You talked a little bit about it.

From your perspective from AEP what I'm interested in is, AEP, when they're trading on the margin, are they typically within their control area?  Or are they trading -- selling within their control area a tier away? Or are they also trading further on out?  What's the market look like?

MR. PACE: In terms of actual transactions, I believe it's fair to say that the bulk of those transactions tend to be with first-tier entities, although in today's world you don't necessarily know if the ultimate power sink is more than the first tier away.

MR. PEDERSON: You make a serial and then it moves on out.

MR. PACE: Correct.

MR. PEDERSON: Also, on the competing supply again, can we talk a little bit more about if we've got a number of generators within the control area and we're focusing in on it, is there a historical transmission data to be able to determine which generators are typically able to run during peak times and nonpeak times and how did we get that?

MR. PACE: Let's see if I've got your question down correctly. I think it is relatively unusual in my experience to have a generator that is significantly limited so that it actually can't run at something near its rated capacity in peak times.

In fact, if a generator is limited by external circumstances, their rated capability should actually reflect the existence of that limitation. But beyond that control area operators would be most knowledgeable of any constraints that prevented it from running generators at that capability.

MR. PEDERSON: How would we identify the load pockets and see how power is flowing into load pockets in that control area?

MR. PACE: That is not an easy task because there's not been public data around that will tell you that. My own view is that when the applicant market base is a control area, it is reasonable of you to ask them as part of their screen analysis to identify significant transmission constraints internal to their control area.

MR. PEDERSON: I guess the other part of what's on the back of my mind is what happens if they are not the IOU themselves. They're an independent generator power marketer that may own generation within an IOU, our transmission provider's control area.

How are they going to get this information to do their own study when they come to the Commission?

MR. PACE: That's a nontrivial problem. We tend to think of the control area often as the applicant. And they have a lot of information. But there are, of course, many independents that don't have that kind of information.

I think if I were in your shoes, what I would do is ask an independent that doesn't have that kind of information. They should be able to use the control area as the default position.

On the other hand, if internal constraints had been identified in prior market-based rate applications by the control area, or if they are clearly identified in reliability reports for the area, it seems to me it's incumbent upon the applicant to recognize that knowledge and reflect it.

MR. PERLMAN: So when the situation where it's not the TO coming in and they use the control area as the market, if there's objections to that approach, the party will come in with the information and provide that information.

MR. PACE: That certainly is one way to proceed, but I also meant to imply that if you already had filed with the Commission a market-based rate application and it reflects constraints, then parties coming along later ought to take that information into account.

MR. PEDERSON: Let me ask one other quick question. I think I heard that transmission often dictates where the market is going to be. Transmission constraints are going to define particular markets. Do those markets shift or change over time and how often does that occur? Or are they pretty static?

MR. PACE: Obviously that depends on the factual situation. If an upgrade is put in two years from now that alleviates the constraint, it caused you to identify a separate market. Then at that point that market ceases to be separate.

I guess I would say from experience most limits are fairly enduring. But on the other hand, the industry seems to be doing quite a lot to address transmission limits and put in upgrades at this point in time. So markets defined by transmission limits will change as the limits are removed or as new ones pop up.

MR. PEDERSON: Thank you.

MR. PERLMAN: Could I ask a follow-up question on the load pocket issue?

In your prepared comments you said something that there ought to be some type of contractual restriction or regulatory restriction to address local market power in a load pocket -- to my knowledge; help me on this if I've made a mistake -- outside of organized markets in the bilateral world. Or the other components of electric markets we don't have such restrictions among generators or sellers.

Would you recommend that we try to identify such load pockets in the event that within such load pockets there was identified local market power and we then impose some type of mitigation or control on pricing?

MR. PACE: Basically, yes. If an application comes in and clearly identifies a local market power problem, there needs to be either market movements or contracts to address that. Otherwise the applicant should not get the authority to sell at market-based rates in that area without mitigation.

MR. PERLMAN: How would you address that with a company, let's say, like AEP. In my experience they sell power on a system basis. If they had excess power on their overall system, they make a system-based sale where some of the units in your example could be in the mitigation load pocket and others would not, and they really wouldn't be differentiated.

Is it a practical approach that you see as being workable?

MR. PACE: Yes, the basic thing you want to do is you don't want to have prices separate and have the ability to charge prices that are very high to people in a certain area because they have no competitive alternative.

One thing you could do, for example, is to peg the prices in that area to the prices in part of the control area outside that area during times when the constraints are binding. Or you could have must-run contracts, which is the other typical approach.

MR. PERLMAN: One other question I have for you is you talked about excluding the retail load and the long-term contracts I would assume. Tell me if you agree with this -- that the long-term contracts you are talking about are contracts that would provide that the buyer has the ability to dispatch a unit.

MR. PACE: Either that or that there's a specified output. In other words, we're selling 500 megawatts around the clock or during all peak hours to someone. That obviously is capacity you can't withhold from the market.

MR. PERLMAN: So they have to be tied in some way to a unit?

MR. PACE: No, there's no reason for it to be tied to a unit. It could be a system sale.

MR. PERLMAN: I would think you could hedge that with another power purchase. And from time to time if you didn't have your units committed to the sale, you would have lots of opportunities to buy substitute or hedged type transactions, which would free up your units.

And if we freeze-frame this analysis based upon that contract that doesn't commit a unit, that unit -- since there is no obligation, that sale could be made in many ways with the units being available to compete and not be taken out of the market. How do you deal with that issue?

MR. PACE: I think that's a good point. You referred to freeze-framing the analysis. One thing that's important if you're going to recognize native load and contract obligations, as I believe you should, it's very important that you recognize you've got a screen analysis that has a three-year time horizon that by definition has certain assumptions -- which ought to be pretty good assumptions about native load and contracts in a time period of that sort.

But it is clear, yes, the applicant could go and change its market position by way of contracting. They could do that the next morning after they filed the screen analysis.

And I think it's very important as part of the deal that if you made clear if there are significant changes in the applicant's net position in the market, they've got to report that back to the Commission.

MR. PERLMAN: Together with a sort of revised analysis that would show the impact?

MR. PACE: Yes, I think that probably makes good sense. In other words, if you've got a change that looks like it might well be material -- and I would define material as it might well change the outcome of the analysis that the Commission relied upon -- that it makes sense to report that to the Commission and show how it affects the analysis.

MR. RODGERS: I had a question or two as well. In your view native load obligations have to be taken into account in terms of developing an appropriate screen. The generating capacity that is used to meet native load is also the same capacity that's used to make wholesale sales in competitive markets, right?

MR. PACE: Yes and no. It's the same body of resources, but obviously it's doing one or the other at a given time.

MR. RODGERS: Right, so the capacity at different times is available for both uses. So I'm trying to understand how the Commission should apportion the amount of capacity that in your view should be assigned to native load versus the amount of that capacity that should be apportioned for wholesale use, because the capacity is used for both things.

MR. PACE: Again, I think what you're attempting to measure is uncommitted capacity, capacity that's not committed to the native load obligation or committed already to long-term contracts.

That is basically a process of identifying how much resources does the applicant have and what obligation does it have. And you subtract the obligation from the resources making the allowance for outages and reserve margins. That shows you what it has uncommitted to serve either traditional wholesale loads or make opportunity sales in the market.

Obviously you do that for whatever time period your test is focused on. If you're using a pivotal supplier test and looking at the peak hour of the year, then you're going to look at the expected retail load and contract obligations at the peak hour of the year.

If you were using a test that is going to look at 12 monthly peaks or three or four seasonal peaks, you would again look at the obligations as you would expect them to be at that time.

MR. O'NEILL: Can I follow up on that? I have some small spreadsheet models up in my office where the large utility can redispatch or dispatch its generation and block competitive generation from the market. How would we deal with that?

MR. PACE: Again, I think that falls under the category that was kind of a general question that was put to this panel about when the applicant controls the transfer capability. Obviously I guess the short answer to that is, if you know about it, you need to reflect it.

If the applicant through realistic maneuvers can cause the transfer capability to be less, then that needs to be reflected in the market analysis or else the applicant has to come in in that case with some sort of mitigation, which might be easy enough to design to make clear that that kind of manipulation is not going to take place.

MR. BARDEE: I'd like to ask just a question going back to what Steve was asking a minute ago in terms of trying to allocate resources to a retail market versus a wholesale market.

Just to hypothesize an example, let's say a utility had 10 resources, the first 8 of which on a given day were running or in reserve for its native load obligations and had 2 left that were available for wholesale sales on the spot market for example.

Let's assume for the moment that the cheapest base load unit it owns goes into forced outage. The next thing they do is take unit number 9; is that right? They pull it out of the wholesale market.

MR. PACE: They would certainly not offer it into opportunity sales. They would take it back or else purchase on the market -- whichever is the most economic thing to do.

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And whichever one they did -- whether they turned on the unit 9 or bought somebody else's equivalent supply, then that result in the loss of that base load unit reduces supply in the wholesale market.

MR. PACE: Yes. In other words, obviously if you have a major outage and you've got a fixed commitment as you do in the case of a retail load or a contract, you've got less uncommitted capacity in that circumstance.

And that's one reason why I would suggest that the test take into account at least anticipated forced and planned outage rates so that it makes an allowance for that.

MR. BARDEE: On a different subject, going back to what you're talking about on ATC as a measure, if I understood what you said right, one concern you had about it was that it ignores the fact that uses that are already reserved to imports may be competing against the applicant's resources.

It may be competing supply, but it wouldn't show up that way in our analysis. Is that right?

MR. PACE: The problem is that if you're going to use -- you're trying to measure the extent to which imports can get into a market and compete.

If you're going to use remaining available transfer capability, then to get the right answer you also have to know all of the scheduled uses that are already taking up transfer capability.

And in my experience -- one would think that would be an easy thing to learn, but in my experience it's very difficult to get a complete rackup of the transactions that are occupying transmission import capability.

If you don't do that, you get demonstrably incorrect answers. In fact, I know of specific market analyses that have been done that produced truly ridiculous answers, because you've got a huge amount of imports into a market area during a certain period -- the peak summer season, for example.

As a result, you have basically no posted available transfer capability. And the analyst has very little information about the detail of the transactions coming in, so they don't include those transactions or those resources in the market. Nor do they include any transfer capability because it's already used up. The bottom line is they end up greatly understating the import competition.

MR. BARDEE: If we used the TTC as a measure, would it be appropriate, recognizing what you've just said, to at least deduct out capacity that is committed to long-term imports by the applicant?

MR. PACE: Yes. What you want to affect is capacity that's available for use by competitors, so realistically available for use by competitors. If the applicant is already using up that capacity for its own resources, you want to deduct that.

MR. PERLMAN: A little quick follow-up on that. Why wouldn't you deduct all of the firm capacity that's controlled by the applicant whether it's tied to a long-term commitment or not? It's the equivalent of generation I would think.

And if you take the TTC as the transfer capability, you should report all the firm transmission to the applicant.

MR. PACE: Why would you do that?

MR. PERLMAN: The applicant is controlling that element of the transfer capability for its own purposes. I would think in that circumstance if you're taking the whole TTC, the remainder of what they have, their generation plus their transfer capability they control, and the rest of the market has the remainder so you would have a balance. Would you disagree with that?

MR. PACE: I think I do disagree with that. Maybe I'm not hearing you right, but it seems to me that in your open access tariffs the applicant can't simply reserve the transfer capability for its exclusive use and do with it what it wants to. It has to make it available.

MR. PERLMAN: What I'm saying is, they have firm transmission rights that they've purchased on the OASIS.

Let's assume you're not the transmission provider and they're using those transmission rights to make sales in and out of that market, but other people don't have access to them because they're utilizing them.

MR. PACE: If the applicant is using the transfer capability and it's not available to rivals, although again my only caution would be it depends on what kind of screening analysis you're applying.

If you apply the screening analysis that says what happens if the applicant withholds all of its capacity, if the applicant withholds all of its capacity, it can't use up transfer capability.

MR. LARCAMP: It sounds in any event that in terms of trying to define a geographic market that the Commission will need some rather robust and visible reporting from control area operators with respect to the use of the transmission system -- at least for any control area that's affiliated with any generation that wants to sell in the wholesale market. Is that correct?

MR. PACE: I believe so. What I think is needed -- and this is perhaps more the subject of panel 4 (I'll be back for that tomorrow) -- but I think what is needed, it ought to be made clear in my view that data on scheduled uses and transfer capability has to be made transparent and available.

I don't mean by that identify the individual transactions. But you have to identify the quantities of transfer capability that are used up by scheduled transactions already so that if the analyst can combine that information with ATC (if that's what's available) and come up with a right answer, that's a data hole that I think ought to be filled.

MR. LARCAMP: Then for any significant additions or subtractions from the capability of the grid over that year or two- or three-year period, we should require the control area operator to provide the Commission with an updated analysis reflected in those new figures.

I mean the purpose of this entire exercise is to discipline the exercise of market power to protect customers.

So if the system goes down or the system is expanded, I don't see how staff can make recommendations to our Commissioners unless we are provided with updated information from -- I guess it's the people that still control the operation of the transmission system for purposes of defining the appropriate geographic market for purposes of the analysis.

MR. PACE: If the change is material, I agree with that. There's two things to do.

First, you do a three-year time horizon in the screening analysis. It seems to me it's incumbent on the applicant.

If they expect something significant to change in year two or year three, they ought to tell you about that and they ought to provide -- if it's material, they ought to provide you with a snapshot screen analysis that looks at that circumstance.

Going beyond that -- and as I said, I'm generally in favor of a requirement that any material change that takes place needs to be reported to the Commission and that would include things that you talked about.

MR. LARCAMP: But we could use that snapshot of the transmission system, if you will, updated for significant changes for purposes of all of the analysis for all sellers. Of course, all sellers will have to have access to that information presumably to make their own cases to the Commission.

MR. PACE: Right. There has to be some way -- as an analyst I run into this problem -- there has to be some way that you can in fact come up with reasonable measures of transferred capability to plug into the analysis. Otherwise you can't get to first base.

MR. LARCAMP: If we have firm long-term contracts that are part of the analysis that we are in effect reserving, should we assume that those contracts are expiring within the three-year period? In the absence of a re-up shouldn't we just assume that that capacity is going to be available?

MR. PACE: Yes, after the expiration of the contract that should be the assumption. That would be part of what I would include.

When I say the applicant should take a three-year look in effect, what I really suggest is the applicant should use the common year effectively as the test year, then report any significant changes it expects to happen in year two or three.

And if there are such significant changes, it might provide the screen analysis for that period. I would certainly include in that a major contractual obligation that is expected to expire, say, in a year and a half out into the future.

MR. LARCAMP: Would it be reasonable if those changes are significant as defined by the Commission to attach a refund condition during the second and third years until the Commission has had an opportunity to review at least sales for that additional amount of capacity?

MR. PACE: I believe the better course would be if the applicant can pass the screen analysis in the first year and a half, for example, and there's an unexpected change that results in it not being able to pass for the last portion of the period and it can otherwise convince you through further analysis that there's no market power problem, I would think the best way to handle that would be give the market-based rate authority for the year and a half period. And they would have to come back.

MR. LARCAMP: Would that be for transactions that only expired in the year and a half or for those that are longer than a year and a half?

MR. PACE: That's a good question. I think that would depend on the specific facts. You'd hate to prevent an applicant from engaging in long-term contracts.

MR. LARCAMP: We want to make sure they are not exercising market power.

MR. PACE: That's correct.

MR. LARCAMP: So the burden should be on the applicant. If there's any doubt, we just say no market-based rate authority for that type of transaction.

MR. PACE: I have to say I hadn't thought that through, but logic would suggest that if you're dealing with a customer that you sincerely think that a year and a half from now you are going to be in a position to exercise market power over that customer, then you would presumably be able to extract that market power in a 10-year contract with that customer.

MR. LARCAMP: We're coming back in terms of our discussion about significant changes within the three-year period, that if the change is significant enough that it changes the analysis, then maybe we ought to consider truncating the three-year period.

MR. PACE: Right.

MR. FRANKLIN: I have a question that kind of adds on.

MR. RODGERS: Last question for Dr. Pace.

MR. FRANKLIN: I'm going to say it in a couple of parts and hopefully it will go real quick. To kind of piggyback on what Dan said, we'd envisioned this analysis to be historical -- historical looks at transmission from point-to-point reservations historical demand, historical supply.

What you're proposing is perspective, correct?

MR. PACE: It's perspective. My impression is that most market-based rate applications, the ones that I've been associated with, have been perspective in the sense that they try to look at the expected loads and resources during the coming peak season and they don't look backward.

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In other words, they do reflect new entry, for example, where the generator is already under construction and expected to come into service in the time period. And they reflect expected load forecasts and obviously contracts that are expiring.

MR. FRANKLIN: Isn't it true sometimes those generation additions or transmission additions get delayed, for example, in the underground cable between Connecticut and Long Island. That got delayed quite a bit. So you never know when those things are going to come in and the future is a little less certain.

MR. PACE: That's why I've always counseled more or less a 12-month future test year. You're not looking very far into the future. But what you are clearly doing is you are taking on board information that you would have a high level of confidence about and in terms of things like generators being delayed.

That can happen. You use very conservative rules. And that's how I would handle that.

The other alternative is to look at history and ignore that you have absolute confidence is going to happen in the next year.

MR. FRANKLIN: One other really just quick question. You have a transmission with a load area. You have four or five tie lines into that area. Each one has an ATC or TTC associated with it. To add them all up is a very liberal way to do it.

MR. PACE: Wrong.

MR. FRANKLIN: Are you suggesting that we take like the maximum of those tie lines as a guide, because you made the comment about simultaneous input capability, which goes to the issue of how much can you load these lines simultaneously with the maximum amount of competitive generation into that market.

Do you have a method for doing that? Because we've struggled with that quite frankly. Without a flow-based model in the interim area we're not dealing with flow-based.

MR. PACE: Yes, there is a method we've used in the past. I don't think you can demand perfection on this, but what you can do is, many times its a clear tip-off because the reported TTC or ATC will be the same number and will vary the same over time for two different control areas that are in a certain direction from the applicant's area.

So you're tipped off right from the get-go that that is likely one set of constraints.

MR. FRANKLIN: You'd use that?

MR. PACE: I'd start applying that common sense check. But what I have suggested in the past is that you can look at the elements that limit the transfer capability to study or identify the limiting elements.

If you then go and you verify that intuition you had that the limits from these two control areas to the south, for example, are the same limit by looking at the elements that are the limiting elements and determining the transfer capability and that they are basically the same limiting elements, then you treat those as simultaneous. Do not add them up.

That's the approach I've used.

MR. RODGERS: Thank you very much, Dr. Pace. We appreciate that.

We're now going to turn to our next panelist, John Apperson, the Director of Trading for PacifiCorp.

MR. APPERSON: First, I want to thank you for the opportunity to provide these comments in this forum and explain a little bit about PacifiCorp and about the West.

I'm senior manager of the commercial trading merchant function as PacifiCorp, and I deal with trading policy and operations issues daily. By the way I have provided a handout to staff and Commissioners that's in bullet format.

PacifiCorp is the third largest industrial and utility in the West. It's load generation and contractual obligations are widespread throughout the western interconnection.

Pacificorp serves one and a half million retail customers over six states, has 8,000 megawatts of generation, is active in virtually every market. PacifiCorp's merchant activities are used solely to serve retail load at low cost. PacifiCorp I should say has been a leading proponent of the development of a good RTO in the region for many years. In fact, I would not be here today but for circumstances outside our control.

The western interconnection has several unique characteristics including a significant number of both small and large non-FERC-jurisdictional market participants and an atypical energy-limited, hydro-based system in the Pacific Northwest.

I'd like to make four primary points pertinent to the subject of this panel and then follow up with a summary.

My first point: The focus of the SMA proposed alternative screens on control areas is both misplaced and incompatible with the portfolio approach commonly used by utilities and their sellers.

The relevant geographic market in the West should not be defined as a control area. Control areas may be a rough proxy for markets elsewhere, but not here. In the West we're dealing with a single large interconnected market with virtually all areas influencing each other, albeit with occasional load pockets.

Thus, to fairly evaluate market power in the West, the broader market, the entire Western interconnection, should be used as the applicable market for a first-tier screen.

Load pockets should be used as the applicable market area for a second tier screen with data provided by the applicant drawn from the transmission constraints published by the Western Electricity Coordinating Commission.

If, however, control areas are utilized as an interim screen, a failed test should be followed up with an explanation by the applicant supported by redefined market boundaries with data supplied by the applicant and should not result in automatic mitigation.

The second point. The transfer into a market area should use total transfer capabilities and should not be limited to the surplus in adjacent market areas.

Nonfirm transmission is often available even though firm available transmission capability, ATC, is not. Therefore, TTC is a better estimate of the transmission capability available in the spot market.

Further, TTCs are subject to extensive review process in the West and are published by the WECC. Moreover, surplus power is often supplied to a market area from multiple nonadjacent market areas.

The third point. The significance of nonjurisdictional utilities in the West cannot be disregarded if FERC adopts an interim generation market power screen and mitigation measures unless the SMA rule is applied uniformly.

The mix of jurisdictional and nonjurisdictional market participants within the same market may result in unintended RTO consequences and market distortions. Any market participant, including nonjurisdictional market participants, may benefit by arbitraging between the prevailing market price and jurisdictional market participants under a mitigated cost-based price, because nonjurisdictional market participants gaining competitive advantage with mitigation but would be subject to RTO market rules putting them back on the level playing field.

Imposing mitigation measures could impede formation of a good RTO in the West. Further, jurisdictional market participants may fail a screen as a result of the expected generation availability data submitted by a nonjurisdictional participant.

My fourth point. Neither the SMA nor proposed alternative screens would work for the West with its hydro-thermal system. Nameplate hydro capacity is not a reliable measure of a market participant's potential ability to exercise market power.

A screen should take into account the energy-limited nature of hydro generation due to limited storage capability and environmental constraints, which result in restricted capacity.

With a notable exception, PacifiCorp agrees with the Bonneville Power Administration's submitted comments recommending (1) derating the capacity to that which is supportable by energy for run-of-river plants, that is, plants without significant storage, and (2) derating capacity to a sustained peaking capacity for plants that do have storage.

However, for these derates, PacifiCorp recommends using average hydro conditions rather than Bonneville's adverse hydro conditions.

Finally, actual hydro conditions should be used prior to any mitigation.

In summary, the points I will make are any interim market power screen used for market-based rates must first properly account for limitations on available capacity for energy-limited resources like hydro; second, by used only as a screen to initiate further investigation rather than as a mitigation trigger; third, treat screen failures on a case by case and region by region basis to avoid unintended results; finally, be applied in a manner that does not convey nonjurisdictional entities that competitive advantage or result in market distortions -- two current features of the Western market.

Nonjurisdictional entities and hydro capacity limitations will result in unintended consequences if the policy recommended for other parts of the country are applied in the West.

This reinforces the need to move toward a Westwide screen as soon as possible in a generic proceeding and apply case by case regionally appropriate determinations in the interim.

That concludes my remarks at this point. Thank you for this opportunity.

MR. RODGERS: Thank you very much, Mr. Apperson.

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Questions?

MR. PERLMAN: I have three quick questions. Are you recommending that we have one single screen or one single analysis that would then have the entities with market power fall out and the entities that do not get market-based rates in a single process.

MR. APPERSON: We're recommending a Westwide screen. We're recommending defining the market area as Westwide as a first tier rather than as a control area.

MR. PERLMAN: And have then individual entities make filings about their own circumstances.

MR. APPERSON: Yes. If those entities fail the initial screen, then yes, they would follow up with particular circumstances that would be applicable to them.

MR. PERLMAN: Two other very quick questions. You emphasized -- that's TTC's -- are addressed with some scrutiny by the western interconnection. Are ATC's less reliable than TTC's in the West?

MR. APPERSON: ATC's do not have the same scrutiny as TTC's. TTC's go through a very onerous process through the WECC. ATC's do not. They are based on the transmission providers OASIS.

MR. PERLMAN: So they would be less reliable and there would be more scatter shot hit in this whether they were accurate?

MR. APPERSON: They have a potential to be because they don't have the same scrutiny.

MR. PERLMAN: And you talked about actual hydro conditions that have been used prior to mitigation. Would that be some sort of real time process where there would be an analysis a day ahead, a week ahead, or something like that to determine whether there should be mitigation with respect to hydro facilities?

MR. APPERSON: It could be season ahead. There's a relatively small amount of storage in the Northwest, so looking out as far as three years we can't really assume anything but an average year as a prediction.

Therefore -- once you get into a year though, the water year could be quite a bit different than average. So if there's a failed test at that point, we're recommending that you take a look at the actual hydro conditions that might change the results of the screen.

MR. PERLMAN: Thank you.

MR. O'NEILL: Can I follow up on that? All the analysis that we've done of the West sort of tends to imply that the only time, or most of the time when there's more potential is when there's extreme hydro conditions, extreme meaning low, very low, hydro conditions.

Otherwise there's lots of power in your market.

There's lot of competing supply. And there's excess capacity. Only when the market tightens up due to a lack of hydro capacity do you have market power problems.

As I hear you saying it, we do the analysis on average capacity and we all know what averages do for analyses. But then if in fact the hydro conditions turn bad, we implement mitigation procedures.

MR. APPERSON: If the hydro conditions are adverse or critical, we are recommending redoing the screen based on those conditions for the period of time for that hydro year.

MR. O'NEILL: Is there any need to do a three-year review if every time there's a bad hydro condition you have to redo everything?

MR. APPERSON: Adverse hydro on average occurs maybe one out of five years.

MR. O'NEILL: But that's a big event.

MR. APPERSON: Yes, it's a very big event.

MR. O'NEILL: From a market power point of view, that's where you need focus.

MR. APPERSON: That's correct.

MR. O'NEILL: So then what would be do in a bad hydro year? After we found that there was market power, do we have something in place that we could just simply trigger?

MR. APPERSON: Well, I'd recommend that the same procedure that was being used for the try and yield test will be revisited at the point when the poor hydro year was discovered.

MR. O'NEILL: We don't have a lot of experience with mitigation entities failing a triennial test. I was wondering what you would recommend.

MR. APPERSON: As far as those that fail the test and looking at a case by case basis allowing the applicant to provide any mitigating circumstances, then the mitigation that is being proposed would be not allowing the market-based rates for the period of time for the low hydro conditions.

MR. MERONEY: Does that mean in effect we'd sort of be conditioning all rates in the West on a one-year review of hydro conditions?

MR. APPERSON: Yes, it does because hydro is not forecast actually beyond a couple of seasons.

MR. MERONEY: This would be predicated on doing the initial test on an average basis.

MR. APPERSON: That's correct -- on an average basis.

MR. MERONEY: And if you did it on an adverse year, say, a standard adverse year, you are getting some of the EPA analyses. Would that be too stringent?

MR. APPERSON: It could be too stringent in a couple of ways.

One is for a utility that owns a significant amount of hydro, for the applicant test based on either critical hydro or adverse hydro would not be stringent enough because it showed they didn't have as much capacity at the same time I test for an applicant in the same market area as an entity with a large amount of hydro could be harmed or shown that they failed the test under critical hydro.

But they wouldn't be failing the test if the other entity and if the market area was using the average hydro because it would show that there's more capacity available in the market.

MR. MERONEY: Wouldn't that mean that if we did it the other way, when we did the one-year check, all of a sudden we'd have to deal with all these problems, because they'd come up when you alter the hydro conditions in a way that they hadn't come up when you did them on an average basis.

We're trying to make it practical and that's an awful lot to do on a year-by-year basis -- one, just to do it and, two, in terms of trying to figure out how to deal with all these contingencies.

MR. APPERSON: Yes, but the probability is that with the try and yield test, the likelihood is significant that there wouldn't be a critical hydro year within that period.  Therefore, to use the critical hydro assumption may result in other entities failing the test for the three years where they would not fail the test in their average conditions.

MR. PEDERSON:  If the Commissioner were to adopt going with an average run-in time for hydro, wouldn't there also need to be a corresponding adjustment to the peak load?

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Right now the way the generation screens look at load and generation look at nameplate capacity and peak load, if we're going to reduce the amount of generation to some average, wouldn't there also need to be the corresponding reduction to the peak load to get them back on the same plane?

MR. APPERSON:  No, the two are independent.  If a peak load analysis -- I can speak to whether or not to use a peak load analysis -- but if a peak load analysis is used, you're suggesting a reduction in the hydro capacity to meet that peak load, so we're talking about a hydro capacity number based on the restriction available as a result of reduced fuel, if you will -- water behind the dam for those hydro generators.

So we're not talking about -- it's a subtle point. We're not talking about using average generation out of the hydro plant. We're talking about using the expected capacity from the hydro plant, which would in turn be based on what amount of generation could be supplied.

We're suggesting using the average water year to base that generation on versus a critical hydro number.

MR. RODGERS: More questions?

Commissioner Kelly.

COMMISSIONER KELLY: What is it about the West market structure that makes it different from the control area model?

MR. APPERSON: Based on our experience in general, the market prices in one area influence market prices throughout the West. There's a very high correlation among prices throughout the West. Therefore, that's telling me that it's really a single market.

We experienced this, of course, with the market prices in California. Originally we picked California, but market prices were high all over the place within the West.

That tells me that there's a very strongly integrated market. That said, there are times when due to certain circumstances -- whether it's hydro conditions in the Northwest or outage conditions in California -- certain markets do break apart.

The basis increases so there could be situations where there would be market power in the particular areas. But I'd say that in general it's a very integrated market.

COMMISSIONER KELLY: When you say that sometimes the markets break apart, is that based on generation shortages or is that transmission?

MR. APPERSON: When the basis increases, that is due to transmission constraints, if there is enough transmission -- we'd better say that.

COMMISSIONER KELLY: Just for an overview, a ballpark, in the past how often have you seen that happen, say, on an annual basis?

MR. APPERSON: I'll preface this. There are -- the markets tend to move together the vast majority of the time. It's hard to come up with a percentage. But it's well over 50 percent and probably approaching 90 percent of the time.

Markets are independent a very small amount of hours. I don't have that number with me.

COMMISSIONER KELLY: That's a good ballpark. Thanks.

MR. MERONEY: John, if we took an approach a little bit the way I believe Dr. Pace was suggesting, which was if you start with the control area but you open it up insofar as there aren't realistic constraints in delivering power to that control area and other control areas, would that work at all in the West in the sense in which you do a few like that and that would become the sort of paradigm for subsequent analyses?

Because if the West is as open as you're suggesting, it should -- any analysis that starts with any of the particular 32 or whatever control areas in the West should sort of lead you to that conclusion, shouldn't it?

MR. APPERSON: I'd have to think about that a little bit. It could. By not restricting the TTC to the surpluses in the adjacent control areas it could. I'd have to think about that.

MR. RODGERS: Why don't we go on to our next panelist. Thank you very much, Mr. Apperson. We very much appreciate your comments today.

Our next panelist is Jesse Tilton, the CEO of ElectriCities of North Carolina. Welcome, Mr. Tilton.

MR. TILTON: Thank you very much. I'm also here appearing on behalf of APPA and TAPS.

I'm not here to spout a lot of economic theory or get into deep technical analysis. I have two key people on my staff, Clay Norris and Janice Kearney, who would be happy to get into those very detailed areas with you.

What I want to do as the chief executive officer is really provide a window for you of the real world that ElectriCities and other APPA and TAPS members face every day as we go about our long-term power supply planning.

Load-serving entities like us must plan and use the long-term markets to meet the needs of our retail customers.

ElectriCities and the other members would urge the Commission to examine market power in these long-term markets, not just the hourly markets that take up so much of our attention. Our eastern agency is in a significant net short position -- 630 megawatts of jointly owned capacity meets only a portion of our load requirements, with the remainder now purchased from Progress Energy under a contract ending December 31, '09. At that point we'll need about 1,200 megawatts of capacity and associated energy to replace the CPL contract.

In other parts of the Southeast there's a generation glut. We cannot access it. In reality we're limited by the CP&L East control area.

It's a -- the grim transmission situation is spelled out by CP&L in response to a transmission request submitted recently by the North Carolina cooperatives seeking 250 megawatts of annual transmission with rollover rights beginning in 2005.

The CP&L study on OASIS indicates that even with infrastructure improvements only 100 megawatts of import capability is available in '05 and 0 in 2010. Most ominously the study identified no known fixes that will allow any imports over and above what has already been confirmed beginning in 2010.

In short, in 2010 we would be in the market for 1,200 megawatts, but there is no firm transmission availability for imports in Carolina Power and Light's east area.

The derivation of the posted figures for ATT also concerns us. We understand that CP&L sets aside 1,500 to 1,800 megawatts as TRM, which is deducted from TTC and thus reduces the amount of transmission available for firm imports.

Our assumingly impossible transmission problem is not readily remedied through the construction of new generation by us or others. Eastern North Carolina's natural gas infrastructure is woefully inadequate. We have a significant area of the state that has no natural gas service in the East.

And that's reflected by an absence of merchant-generated plants in eastern North Carolina. There's no interstate pipeline that's crossing the CP&L east control area.

Furthermore, if the new generation that is installed triggers a participant funding requirement, the total cost of the new generation would be prohibitive and uneconomic.

CP&L is currently the only option. And its market-based rate authorization does not obligate it to continue to sell supplemental capacity and energy to us at reasonable rates.

How is the competitive market disciplining CP&L's incentive to extract excessive rates? Does this produce the just and reasonable rates the Federal Power Act promises?

As I've stated in recent testimony at the North Carolina Utility Commission, after the summer black-out, we believe there is a need for a bottoms up approach at the state level led by the NCUC to fully address this transmission infrastructure crisis.

Transmission owners, transmission-dependent utilities, and all of us interested in keeping the lights on need to come together and look at this issue.

The native load customers of both have provided rate revenues to build, operate, and maintain the transmission system. The customers are intermingled across North Carolina, often just across the road from each other.

One set of native load customers should not be given priority over the native load customers on another utility that may be a transmission owner or regulated by the state utility commission.

We have met informally with the NCUC, the public staff, and representatives from Duke, CP&L, and the cooperatives. I am confident that moving forward with the leadership of the NCUC and the public staff and the interest they've taken in this will help us reach a solution that could resolve this problem.

But I would ask that the FERC keep a close eye on all work in the Carolinas to be sure that this problem can be resolved. It is a daunting task. CP&L knows of no transmission solutions to resolve this issue.

Here are the lessons that we've learned from our experience. In looking at long-term transmission supply TCC does not reflect the capacity available to consumers relying on a transmission system. The Commission must at least look at ATC. And there may other factors that would reduce that figure.

Independence and consistency of transmission capacity calculations is needed. The geographic market definition must reflect the actual purchasing and selling practices in the region.

The Commission's examination and mitigation of hourly markets ignores load-serving entities' service obligations for the long term and leaves us vulnerable in this long term market to market power.

Rejecting or mitigating requests to sell at market-based rates is a temporary solution. We need structurally competitive markets if we are to succeed in keeping the lights on across the country.

That would require at least the following: transmission under the control of a truly independent ISO or RTO; continued application of market power tests for the market-based rate authorizations even in areas where there is an ISO; and the need for a transmission infrastructure funded through rolled-in rates sufficient to support the competitive market that is the basis for FERC's approval of market-based rates.

Thank you very much.

MR. O'NEILL: Can I summarize what I think you just said? You have asked for transmission capacity to get to potentially other suppliers other than the utility that you're nested in. They said no, it's not available. And the only alternative is the utility that you are situated in and they have market-based rates?

MR. TILTON: That's close. We did not make a transmission request. Another wholesale customer in the area, the North Carolina Electric Membership Cooperatives, put in a request on OASIS for 250 megawatts starting in '05.

So it was their request, not our request. In our routine power supply activities we were monitoring that. We took notice that the study response from CP&L was that in fact there was a very limited amount of capacity between '05 and 2010.

There is a CP&L study on OASIS -- you can access it -- which indicates '05, '06 about 100 megawatts with some transmission additions. But when we get to '10, it's a 0. After '10 it's a 0.

Even if there might be some additions -- yes, where we see ourselves from a long-term standpoint is, we have a contract, which we'll need to replace in January of '02. It's in the amount of about 1,200 megawatts.

There's no transmission import capability, so our alternative is to look to CP&L in the area who has market-based rates that would not have an obligation electric service.

MR. O'NEILL: Do you just happen to note what their posted TTC is?

MR. TILTON: No, I don't. But we would have concerns with TTC. And this is, I think, a prime example showing that TTC, while it might give some idea of line capabilities that are out there, does not look at how a system actually operates.

If we understand the ATC study that was done by CP&L, this is a relatively complex situation of systems, interfaces, and operations that lead to this zero import capability.

Simply looking at the capacity of the lines coming into the control area certainly in this case would leave a very false idea of the amount of competition available.

MR. PERLMAN: Can I ask a follow-up question, I guess, along these same lines, but coming at it from the other way on the contract side.

As I understand what you said, you have a contract through 2010. As I understand, many of the comments we received and some of the folks' proposals, we would take the capacity associated with serving that contract out of the picture in doing a market-based rates analysis because there's a long-term contract associated with it.

Do you have any comments on whether that's appropriate?

MR. TILTON: The capacity would be used up, so it's not available for someone else to have a competitive come in and import. So yes, any contracts that are done reduce the amount of ATC that's available, which closes off competition.

And I think that the limit here -- as Dr. Pace was saying, yes, those are competitors coming into the area so on the one hand it seems like there's competition here.

But if you have unserved load in the area, I don't care whether there's competition somewhere else. If the lights are out in eastern North Carolina, there's a big problem.

MR. PERLMAN: I'm asking it really differently. I understand from a transmission standpoint what you mean.

What I understand, for example, Dr. Pace is suggesting is that the generation would be subtracted so that only the marginal generation that isn't used to serve your contract and the native load would be considered in the market-based rates analysis.

And therefore, there would be potentially no generation -- 10 megawatts or something like that -- and that would be the remainder that would be looked at to see whether there was a competition in market-based rates.

MR. TILTON: That would be the norm -- turning flow around at the end of our contract and competing somewhere else so CP&L has generation there that is in the wholesale market and is available for competition. Likewise on the retail side.

Certainly you wouldn't want to include all the generation that's committed to retail load customers. On the other hand, you cannot ignore all of it either.

This is a system that generation might be used for one hour of the year to meet retail load. Then what about at the lowest load level of the year, there's an awful lot of generation that is there in these hourly markets that have become quite common.

That certainly is an opportunity to use this generation dedicated to retail in a competitive market. So I don't think you can just say generation dedicated to retail customer service in the latest retail rate case is exempt from this calculation of market power.

Certainly substantial amounts of that generation find their way into the competitive market in a large number of hours.

MR. RODGERS: I had a couple of questions. You mentioned that CP&L had set aside a significant amount of capacity for PR. That's to serve their native load customers, right?

MR. TILTON: I would understand -- I'm not sure I know what the basis of their TRM set aside is. That would be a question we would want to have answered. It is a large amount of set-aside.

MR. RODGERS: And it's not available thereby for you to use in trying to get the transmission service to meet the needs of your native load customers.

MR. TILTON: CP&L's view is it's not available. Perhaps some further study of this might reveal that some significant portion of that 1,800 megawatts of TRM would be available.

That points us to another concern that we have in this proceeding. There needs to be some outside independent review. There needs to be consistency on how these things are calculated.

Certainly we're not launching an accusation at CP&L for the way they calculated it. But we're saying that there needs to be some review and scrutiny of how they are calculated and then consistency applied to the various calculations from different market players.

MR. RODGERS: Because there's no such transparency that's in the marketplace now, no way for you to verify or anybody else to verify, when an IOU sets aside a certain amount of capacity for TRM, if in fact that is the proper amount that's needed. Is that correct?

MR. TILTON: Yes.

MR. RODGERS: You mentioned that one set of retail customers should not be given priority over another set of retail customers. Is there anything that this Commission is doing that's causing that? What is driving that?

MR. TILTON: One of the concerns of the discussions in the Energy Policy Act about service obligation and how you deal with an emergency on the transmission system, we feel that the reliability that is provided should be to all load-serving entities regardless of whether they are an owner or a non-owner.

MR. RODGERS: Do you happen to know approximately what percent of the retail customers in North Carolina are served by the IOU's?

MR. TILTON: That's a substantial number. I don't have the precise number, but on the order of 80 percent.

MR. RODGERS: That means that the remaining retail customers, 20 percent at least, are served by coops and munies in the state.

MR. TILTON: Yes.

MR. RODGERS: Do you know if the rates -- well, I'm sure you do know the retail rates that are set by the coops and munies -- are they under the regulation of the NCUC?

MR. TILTON: No, there are not.

MR. RODGERS: Last question. Is there anything that CP&L or the NCUC is doing to try to address these transmission needs that have been identified?

MR. TILTON: As a result of our contacts and urging for the parties to come together and work on this problem we have received a positive response from CP&L, from the NCUC.

We're hopeful that collaborative process working from the bottom up locally is going to produce a solution. But we hope that's the case. It could produce a solution.

We would ask that FERC just keep an eye on that.

MR. RODGERS: Thank you very much.

Why don't we go on to our next panelist. Hopefully there will be some time at the end for some more questions of any of the panelists.

Thank you very much, Mr. Tilton for your thoughts here.

Our next panelist is Ricky Bittle, Vice President of Planning, Rates and Dispatching of the Arkansas Electric Cooperative. Welcome.

MR. BITTLE: Thank you. I'd like to thank the Commission for continuing to look at one of the most important aspects of setting market-based rates. That's the potential for the exercise of market power.

I'm really pleased the Commission is really looking at what is the relevant market rather than just setting a market and assuming there will be a workably competitive market there to participate in.

I work for Arkansas Electric Cooperative Corporation. It's the G&T cooperative in the state of Arkansas. We serve 16 of the 17 distribution cooperatives in the state. We serve about 25 percent of the people and cover about 60 percent of the geographic area. The load is dispersed over the load-control areas of Entergy, AEP and in the Southwest Power Administration. We do not own a significant amount of the transmission. Any transmission we own basically is radial, so we are in the market at times.

We do own enough generation to serve all of the load that we are required to serve. We are regulated both at the G&T level and the distribution cooperative level by the Arkansas Public Service Commission.

In general we agree with a lot of the things that we've heard here today. What we're looking for is something that in the long term benefits the consumers. We're not looking for an unregulated monopoly selling at unregulated prices.

We know in the long term high prices are just not going to be politically acceptable. As far as the load control area is concerned, I don't think that's the right place to start. It really is engineering definition.

And just for your information, I am an engineer. So I can hide behind that just as well as Mr. Tilton hid behind the fact that he's the CEO.

(Laughter.)

MR. BITTLE: But just to move forward, the transmission rates are extremely -- our transmission definition is extremely important when you start looking at the market.

Of course, you've got to look at which product definition you're really talking about. Are you talking about long-term? Are you talking about economic energy? Or are you talking about one of the ancillary services?

I think everybody recognizes from what we heard that transmission is the key in defining what is the market area, no matter which of those you're looking at.

The main goal we're looking for is multiple buyers and sellers. So even after you start defining your market just because there's excess generation in the area, if you've just got one dominant buyer, you still may not have competition. So it's got to be looked at from both directions.

I think one of the other big things is the idea of load pockets. Load pockets really are transmission limitations that limit the ability of consumers to choose which generation is going to be used to serve them depending on the pricing system.

If you're using LMP, it may impose extremely large prices, large enough that they are scarcity rents and actually above any cost that anyone is incurring.

And then the question really as far as the load pocket is concerned is, well, if you're doing that, where is that money going to go? How is that scarcity going to be used in the long term? Is it going to be used in some way that's going to benefit those consumers?

Or is it just going to be something that they continue to pay even if there's no one that can step up and actually build something -- either transmission or generation -- to get to them because of other problems such as you see in general areas where you don't have gas. You don't have any way to get new generation built, and the transmission is going to be an extremely long-term solution if at all.

MR. BITTLE: I think everybody who looks around and sees transmission that's being built can find real examples of how long it take something to get something build. AEP took 15 years to get one piece of transmission built. You never know for sure what it's going to take to get something built.

And so when you start looking at the import or even export capabilities, one of the things you're starting to look at, as well as is TTC the right measure, TTC may be there if you're only looking at a single little phase, but if you're looking at the total, either into a market area or into a load pocket, the simultaneous import capability becomes much more important.

Also, you may have to actually look back and see how was the import capability actually allocated between consumers to get a real good idea of what's going on. When you're looking at transmission, as far as I'm concerned, one of the other things you've got to look at is, are you erecting a barrier to entry.

To me, when you start looking at participant funding that requires a new generation, to fund any new transmission that's needed, whether it benefits other consumers or not, you are erecting a barrier to entry. So it's one of those things that you really have to take into consideration.

As far as the screens that you're talking about and excluding the retail load from the generation, I think that becomes a mistake in that you really have to look on an hourly basis almost to see how that generation is used. We've already talked about the fact that when you have a portfolio of generation, you can use that in a lot of different ways to sort of both retail or wholesale and if you're screen is not matching the way you actually using the generation, then you're exposing yourself to a misinterpretation of what's going on.

By doing that, you can also come up with some problems where you actually attribute market power to somebody in the region that really doesn't have it. So you can go both ways with that but if you're going to actually do, then maybe a limitation on the way that generation is used is correct. In other words, might the use of the generation match the screen that you're using, if it's a wholesale market screen, the way you're proposing to use it, perhaps one way to do it is actually to limit the use of the generation that's being assigned to the retail load.

Now you have made a significant improvement in that by going to a monthly calculation, but if you limit the market power, or limit the ability to sell at market based rates to only the portion of the generation that is not assigned to the retail load, then you've made a step in the right direction.

If you go through the screen and you come out with an answer that there is no market power and so they can use their entire portfolio of generation, you basically have given them something that's the best of both worlds.

The other part of it is, if you're going to make sales out of that generation that is aside to retail loads, maybe it's appropriate to only do it at a cost based regulated rate. Mitigation really when you're starting with a load control area would have to basically the starting point within that geographic area. You really have a dominant utility that has a vertically integrated monopoly and by definition has market power if you come up with a screen basically it makes a 900-pound guerilla weightless. I would question your screen.

The other piece of it is that as far as RTO participation is concerned, I'm not sure I would give just a free pass to anybody that joins in our deal without really looking at how the RTO is structured and making sure that there is market monitoring going on and that if necessary, that there is an additional market mitigation in place to make sure that that particular area is going to produce a competitive workable market. Thank you.

MR. RODGERS: Thank you very much Mr. Bittle. Some questions. I was wondering if you could tell me, Mr.

Bittle, you referred to load pockets at some length. I was wondering if you could tell me what is the pervasiveness of load pockets in your part of the country, both in terms of the number that there are as well as the duration, if they exist.

MR. BITTLE: Currently, in our area, there is not a market setup that really takes advantage or gives anyone market power within a load pocket because most of the sales at the wholesale rates, the wholesale rates are regulated, so I'm not sure that currently there is, but as we start moving to market, that's where those become extremely important, especially if you move to something like an LMP that actually does price the delivered product in there based on those limitations.

MR. RODGERS: You also suggested that the Commission should focus closely on what are the relevant product markets and developing a screen. Are you suggesting that the Commission should have different screens for different product markets?

MR. BITTLE: I think as the size of the market changes, you may be able to apply the same screen but you have to look at who can actually provide those. If you were looking at, well, load following service would be an extremely easy one there. Load following service is something that's going to take multiple generation.

A single generator is not built to provide load following service. You may have to have a different definition of that because of the number of generators that you're looking at. If you're looking at reactive power because of just the physical limitation of the transmission system and the fact that the reactive impedance is so much greater than the real impedance, that your market just generally shrinks. It makes the number of generators able to provide that a smaller group, and so, I think probably it's the size of the market that you have to start looking at.

MR. RODGERS: One other thing, you suggested it would be helpful for the Commission to look on an hourly basis as to how generation is actually being used in developing a screen. As I'm sure you are aware, for initial market based rate applications, the Commission, under the FPA, must act within 60 days to get an order out. An examination of hours of the year could be quite a bit more time consuming than what we are doing now.

Do you have any solution or suggestion on how to overcome that obstacle?

MR. BITTLE: Reality and simplification are two different things and I recognize that. I recognize that to actually be able to do that would be an extremely large amount of work and would require a lot of pre-calculations, in effect that would have to be done. I don't necessarily think that an hourly screen is what you're going to be able to do to meet your deadline, but I'm just saying that you really want to know how generation is used, you'd have to look at it on an hourly basis.

MR. LARCAMP: Our families thank you.

(Laughter.)

MR. PERLMAN: I want to be sure I understood you correctly because of that mixture of using the same set of generation for retail and wholesale service, did I hear you correctly to say that you might be suggesting that the Commission adopt some sort of combination of cost of service or cost based service for some component of the generation or some number of megawatts and market based rate for a different set?

MR. BITTLE: Yes, as a matter of fact, that was what I was suggesting. I was suggesting that you may want to look at limiting the amount of capacity that would be available for market based rates and anything that is not included in that, be at a cost based rate.

MR. O'NEILL: Picking upon on Dan's earlier suggestion and the complication of analysis. When you can't analyze the transmission capabilities and things like that, would you suggest that if further analysis has to be done after 60 days, that the rates be put into effect subject to refund?

MR. BITTLE: I think that would be an excellent way to do it personally and I'm sure there are a lot of people that wouldn't agree with me but I think that in a lot of cases, the type of data that you collect on an annual or monthly basis even, is going to give you the data or prevent you from having the data to do the type of screens that you're going to need to do.

MR. O'NEILL: What would our recourse be if our rates weren't subject to refund if we eventually found that the initial screen assumptions didn't work?

MR. BITTLE: I guess there is a question there and that becomes one of those legal questions and being an engineer, I won't answer it. Basically there are antitrust laws. I think they would be subject to at least treble damages.

MR. BARDEE: Mr. Bittle, on the cost based rates issue, let's assume for the moment that the Commission ultimately decides cost based rates are not an appropriate form of mitigation, do you have a different form of mitigation that you are suggesting instead of that?

MR. BITTLE: Completely denying the market based rate authority.

MR. BARDEE: Just not giving them permission to sell, period?

MR. BITTLE: Well, sell, but sell at a regulated cap based or some form of a cap.

MR. RODGERS: Thank you very much Mr. Bittle, we appreciate that. Why don't we turn to our next panelist, Ron McNamara, the Vice President of Regulatory Affairs and Chief Economist for the Midwest ISO. Welcome.

MR. MCNAMARA: Thanks Steve. First, let me take this opportunity to thank the Commission and the staff for having us here, representing MISO, as well as myself.

I guess what I'd like to subtitle my five minutes is the continuing education of Ron McNamara because I spent eight years abroad in both New Zealand and Australia, working during their reform process. I resisted trying to learn some of the uniquenesses of the U.S. regulatory system, knowing that we were supposedly going to get to this world that is actually in place in other parts of the global economy. But I'm finding out, that I've been broken down, so I now have had to memorize TTC and ATC and TLRs and everything else. I'm convinced that this world is here, at least for some time to come.

With that in mind, what I would like to do is actually provide -- I'd like to say it's a vision. It establishes a relative baseline for where I come from when I look at this problem, and admittedly, it is an important problem.

What I'd like to do is just jump ahead to some moment in time. I'm not sure when that moment actually occurs, but let's assume we've actually reached a state where energy and transmission have actually been separated and that energy as a commodity and transmission as a service is no longer combined into an integrated service people actually purchase.

In that world, energy will be sold under a vast array of financial instruments, primarily contract for differences or swaps as well as options. Ricky just mentioned another one, which I, in a previous position, have had to try to understand what it is; load following service. In my world, I have no idea what that actually means because people are simply buying energy at various points in time. There is very little ability to differentiate between energy provided from load following services from energy provided from base load services, or something like that.

And since electricity in this world is largely a homogeneous good competitive pressure reduce that margin to a very small level. In fact, where opportunities to add value to the marketplace come from is risk management, which becomes the "dominant job" of people in the industry. There is no necessary reason to define capacity, TTC and ATC in this world, that's largely irrelevant.

Generation simply establishes a long position, load simply establishes a short position and the question is, how do we manage the price risk associated with matching the long and short positions in the most efficient and appropriate way, and do we in fact have the institutional structure that allows that to be accomplished.

The RTO, the ISO, or whatever you want to call it is really the one that is responsible for managing delivery risks, i.e., keeping the lights on. The job of the participants is to manage the price risks associated with their long and short positions.

The capital intensive nature of this industry necessarily means that it will be a relatively conservative industry. I would expect just prudent boards would manage their risks in terms of their debt levels and so on and the length of terms of their assets, with a high level of bilateral contracts. It will not be physical contracts that they're using to cover their risks, they will be financial contracts.

So, with that as a vision, what I'd like to deposit, as a bit of a question here, ultimately we are somehow going to leave behind this physical notion that we occupy today, unless we are going to go back and just island ourselves into very, very small subregions and that's probably the only way that this world continues, given access to capital and growth in markets.

And I guess, as an economist, I believe in the long run, there are no barriers, political or otherwise, and where there is profitable opportunities transmission will expand and generation will expand or to try to stop the forces of the market maybe able to delay the inevitable, but it's difficult to see that it stops it forever.

With that, what I'm trying to understand is the SMA, is the intent largely to become a bridge from the world of physical rights into this world of financial rights or is it intended to be kind of a stick in the carrot in one world to move into the next world. So I'm not actually sure on that actually then. On that condition some of my points I'd like to make in regard to mitigation in general.

First of all, the Commission has made it clear in both their technical working papers and otherwise that this is an interim measure. I've heard some of my esteem panelists up here talk about investment and transmission. The question has to be discussed as to whether or not an interim measure, what is the relationship between an "interim measure and long-term investment?"

I would assume that ultimately our goal is to move out of this interim world to get into RTOs and have some kind of similar mitigation measures applied across that.

The second point I'd like to make with regard to mitigation measures is that they must be well understood. They need not be overly complex. That just adds risk and uncertainty into the market, ultimately increasing price to consumers. So they need to be well understood. Keep it simple as much as possible.

Third, you have to carefully investigate the potential for disincentives and that especially applies where you've got physical to financial or non-market to market transactions. So what are the incentives that apply to this over both the short and long term?

Fourth, there needs to be a limited ability to apply discretion in the application of any mitigation measures. Those have to be fairly robust people, know why they are being mitigated, when they are being mitigated, and how they are being mitigated.

This leads me to the conclusion with regard to the definition of market power. Finally, I think we need to make sure that we include in our analysis the effect of capital markets on any likely mitigation. This is an industry that is in a very fragile state at present. It's not clear how this will affect the terms of contract.

As I said earlier, it is my view that this industry should, by nature, be relatively conservative given the capital intensiveness. I would assume most people would want to engage in long-term bilateral contracts. What affect would any mitigation measure have on their ability to do so?

With regard to market power, I think it's a little bit like applying to another topic. I don't know how they define it, but I know it when I see it, having been on both sides in terms of trying to actually define it.

In Australia, I was trying to contract around with commercial entities. The test here applies to generation, then I would ask, in what market are we talking, belong to a market? Questions have been talked about here with regard to, do we need to look at the contractual position. Again, that gets back to what is the ultimate objective of this and how is the time frame of it. To be effective, I would say yes.

In terms of you do this as a permanent solution or as permanent staff to put in place with regard to mitigation? The spot market and the long term market are two very different animals with regard to risks.

Now I'll get into some of the Commission's questions. The relevant geographic market, I would actually like to add another thing in there, and that is, what is the relative product definition? Are we talking about bilateral contracts? Are we talking about near-term, long-term contracts? Are we talking about spot market purchases?

It would be my assumption -- obviously, one would have to test this with regard to empirical evidence -- that market power, if people are at all rational, is not necessarily, some very prominent cases notwithstanding, is not necessarily exercised in the spot market, that it would be exercised in the bilateral markets and the ability to actually hedge exposure and hedge risk.

So, this test is obviously applied purely to the spot market. I think you have to look whether or not the control area is in fact too narrow of a definition. I think really the transmission system itself and the loop flows define where the market breaks itself into. That may or may not overlap on what we call control areas.

I think the Commission has indicated that this would not apply to transactions going into areas that have a market but I think that also depends upon where the entity sits with regard to RTOs and stuff would have an effect and if you are surrounded by RTOs that may be a little bit different than if you're not, with regard to how you define the geographic market.

Load pockets. I think the fundamental question here is again high prices, inability to contract, inability to get the term and condition that you want. I have heard people talk about, I can't get the contract I want. What is the contract you want? I want low prices and short term. The two sometimes don't necessarily go together and I think we have to look and say, what is the problem we're trying to solve? We clearly have to address the issue of the load pocket.

I don't know that an interim measure is the most effective way to address a load pocket issue because that gets back into the only way you're really going to solve that is through investment in either local plant distribution, generation or transmission upgrades and I think with regard to an appropriate measure for a transmission capacity, it seems to me that ATC is somehow linked or related to the simultaneous capacity, which is really related to the spot market and TTC closer to a planning concept, closely related if you're going to look at the long-term contract market in terms of where the market power is being exercised. So I think it depends on what market you're trying to mitigate the power in.

If we use a characteristic, a defining characteristic of the market, the risk characteristics, clearly spot market is a different market than a three-year contract market. And so, I don't think you can automatically assume that they require the same exact risk mitigation measures brought to bear.

With that I'll open it up.

MR. RODGERS: Thank you Ron, I appreciate it. Questions?

MR. O'NEILL: Ron, suppose someone made a request for three years or more worth of transmission capacity and the TTC said yes it was available, but the request came back denied. How do you assess that situation? Is that market power?

MR. MCNAMARA: It's out of the market, not in an RTO? I think you have to open up the process by which it was determined that it was denied into public scrutiny. People have to have confidence that this is being applied in a reasonable and fair manner.

MR. O'NEILL: That's a hard thing to do.

MR. MCNAMARA: Absolutely.

MR. O'NEILL: What's the answer?

MR. MCNAMARA: Start with providing more information in terms of the process, the detail of how the analysis is done and see if that gets you where you need to. If not, it needs to be done someway else.

MR. O'NEILL: We've tried that several times. Do you have any other suggestions?

(Laughter.)

MR. MCNAMARA: Join an RTO.

MR. MERONEY: What's your position on exempting RTO areas from this?

MR. MCNAMARA: I just was thinking of this when I was listening to other panelists.

MR. MERONEY: Particularly in view of your emphasis on the long term and other products.

MR. MCNAMARA: I think given that they're basic, I think you have to get into whether it's an LMP in place and whether or not we actually have a financial marketplace, which I think provides a different set of incentives than a physical set of structures. To the extent that a market has, I think the LMP and has gone to a pure financial rights basis for dispatching and keeping the lights on, I think that's a different situation and I think you can't exempt it that way. It's a different mitigation process.

MR. MERONEY: Including other characteristics, like sort of long-term instruments and other things like that?

MR. MCNAMARA: Yes.

MR. PERLMAN: In addition to the time differential issue and product market, do you think there are different products so to speak in the spot market through base load, intermediate and peaking where you might want to look at the plants that could actually control the price, the clearing price and leave the other plants. Treat them differently from a product perspective?

MR. MCNAMARA: I think that's related in some part or regard to some of the other market design elements in terms of whether or not there is capacity payments that are being made.

If you have an energy-only market, I think you have to allow companies to get an appropriate return on capital. If you do have a capacity market they are going to receive some capacity payment from providing that "service" as well as and they can basically inflict upon themselves a price cap, which limits their ability to exercise and absorb an amount of market power in the spot market.

MR. HUNGER: Ron, along the lines of the product market definition, under the Commission's merger review under Section 203 of the Federal Power Act, we defined, we have three relative products. Whenever there is a merger acquisition, we have to analyze the effect on competition of these three products. Those are energy, long-term capacity, and ancillary services.

In order to analyze the effect on energy markets, we use the delivered price test which takes into account availability and the running costs of the unit, what units could affectively compete in the energy market subject to transmission constraints and also subject to differences in seasonal conditions, which I think gets to all of the points we've come up with.

There also is the separate product long-term capacity. The Commission has basically determined that absent specific entry barriers, long-term capacity is competitive. Applicants don't have to show that some transactions would affect that.

In revised filing requirements, the Commission actually required that applicants show that ancillary services markets are not affected. Spinning and non-spinning reserves along the lines of what Ricky brought up. While some units may be able to be better suited to provide spinning reserves than others.

MR. MCNAMARA: In particular reactive, yes.

MR. HUNGER: We've got to have the AGC located within the control area and things like that. So you think there is a reasonable product definition energy capacity and ancillary services are to find.

MR. MCNAMARA: Today or tomorrow? In tomorrow's world I don't know how I actually sell energy. What I do is sell a price.

MR. HUNGER: Assume we're stuck in today's world.

MR. MCNAMARA: Then yes they are appropriate. We're still on this quasi physical financial conundrum and I think that in today's world, they are appropriate. But obviously we're going to have to transition into the new world and I do think the point made by my colleague to the right, regarding ancillary services is very pertinent.

It needs to be looked at in addition to just the spot market because the breadth of the ancillary service markets is usually much smaller than the breadth of the energy markets per se.

MR. HUNGER: In today's world, do you think the Commission might revisit the notion that long-term capacity markets are competitive?

MR. MCNAMARA: Yes.

MR. RODGERS: One more question for Ron.

MR. O'NEILL: On the topic of reactive power markets, most of the 888 tariffs, as I understand them don't have any reactive power pricing for independent power producers. Should we modify the 888 tariffs to say, when asked to produce reactive power that you get full compensation?

MR. MCNAMARA: I've been in two situations where brown-outs have occurred because there is a reactive power problem, not any other problem. Reactive power in many cases can be even more valuable than real power. I think it needs to be compensated. But again, that has to be consistent with other design elements in the market and regulatory structure. It may be appropriate not to do that in the current regulatory structure, but on a going forward basis, I do think that it is worthwhile given the importance of reactive power in our system.

MR. O'NEILL: Under the current 888 tariffs, it certainly presents bad incentives.

MR. MCNAMARA: Absolutely.

MR. RODGERS: Thank you very much Ron. We appreciate it. Our last panelist on this panel is Steven Corneli, Director of Regulatory Affairs for NRG Energy.

MR. CORNELI: Thanks very much. I'm happy to be here. I learned a lot already this morning listening to my colleagues here. I'll try to go quickly through my presentation so we can get to the broader discussion.

NRG owns generation in the three northeastern ISOs or RTOs, California, in the upper Midwest and in Entergy. I believe we are Entergy's largest transmission customer, so the perspective I want to offer today is based on a fairly intimate knowledge of mitigation procedures inside RTOs and ISOs, as well as the market challenges and the potential market power challenges in the unorganized or bilateral markets.

Let me start with three sort of high level points that I think are relevant to the questions put to this panel about defining geographic markets and the role of transmission. The first observation is that I think we all need to keep the policy goal in sight as we wade through these complex issues. The policy goal is properly conditioning market based rate authority so that market transactions continue to be just and reasonable.

This means that market power has to be accurately diagnosed and effectively addressed. If we don't diagnose the right disease, we probably aren't going to be able to treat it very well.

The second point is that I think we need to really keep the big picture in sight, sort of nuts and bolts of what would really happen in the exercise of market power as we think about this. In your writings and issuances and orders on this topic, you've accurately identified physical withholding as a primary means by which market power can be exercised. I think we've all seen looking at market indices and market reports that even the loss of a small amount of capacity under the right conditions can have significant impacts on prices and the presence of even a small amount of capacity at the right place.

In the offer curves that are out there bilaterally can have a significant effect on keeping prices from going up higher. However, the SMA test in particular, I think like all of the proposed modifications to it essentially ignores a significant means by which large amounts of generation can systematically withheld from the market.

That means is discrimination in the excess to end use of transmission by people who control transmission systems to grant market based rates to entities that can withhold their competitor's generation. Just because they can't withhold their owner generation would be penny wise and pound foolish in my view.

The third point is to use tools that work. All of the tremendous debate on generation market power needs to take place. There are many details. It's very complex. There is a lot of moving parts but this debate going on, while assuming that just the existence of an open access transmission tariff prevents transmission market powers further reminds me of the Russian proverb. When all you have is a hammer, everything looks like a nail.

Of a special concern, when the hammer is a behavioral remedy and perhaps the real problem is a structural problem that needs a saw to cut through it rather than a hammer to beat it down. You need hammers to modify behavior when that's the most effective policy.

But, when it comes to the ability to withhold other competitors generation from the market and so affect the prices, you have a structural problem. You need a saw to cut through that. You have the saw. It's called Order 2000 and in our view, you ought to use it.

Let me go through the questions you asked for this panel in light of those overall points and show how I think that they really go to the questions you asked us to address.

First, how to identify the geographical market?

The traditional economic approach is reflected as David said in the merger guidelines, is to look at the effect of a price increase. If a significant price increase causes people to switch to other producers' product, those producers and that product are in the market.

In the world we're looking at, if an applicant for market based rates uses transmission market power to keep other people's generation out of the market to engage in physical withholding of other people's generation, the right test, a test along these lines will show a more concentrated market. What that suggests is there is a link between what you might call vertical market power or transmission market power and the horizontal market share that the SMA test tries to identify and what your other tests look at.

That doesn't mean that imposing behavioral remedies on generation market power alone will cure the underlying problem. That can only be done by allowing competitors to access the market. In other words, you need the saw, not the hammer.

The third question is, should we use TTC or ATC to define the market. I agree with almost everything that Dr. Pace said about this and I won't go through it again. Who has rights to use that available transmission? That reserve transmission capacity matters at least as much as how much of it there is.

We would agree the Commission should require transmission owning applications for market based rates to include information on the percent of all available transfer capacity reserved or otherwise retained. For example through TRM or CBM for their own or their affiliates use and should evaluate the ability of the applicant to withhold competitors generation from the market accordingly.

This will be especially important if we move to a monthly assessment as you're talking about in your White Paper because these issues change periodically and a lot of margins can be affected in a relatively short number of months.

The underlying message again is that the vertical component has to be considered along with a horizontal component and market power that takes place outside of RTO's the ability to withhold other competitors generation through discriminatory transmission practices has to part of your analysis and ultimately part of your cure.

The fourth, fifth and sixth questions you asked get even further into the interaction of transmission and generation market power, what an economist might call vertical and horizontal market power.

Competing megawatts certainly matter, but only to the extent they can really access customers to the transmission system. Counting all megawatts without regard for their ability to access the transmission and to get to the same customers will understate the market share and the market dominance of the candidate.

If the applicant for market based rates controls or influences the transfer capability of the system, the dispatch or must run conditions, whether it is through dispatch or contractual terms related to load pockets or to other constraints, naturally the horizontal scope of the market is more limited than a TTC based, all megawatts count equally approach would suggest.

Again, the appropriate cure is not necessarily to treat people as if they have too much horizontal share when the underlying problem is perhaps that they have too much vertical influence over the supply chain.

How does all this relate to the task of considering needed refinements to the SMA test? I guess my key point is that if an entity controls large amounts of generation and also controls transmission access and use, it has both the incentive and the means to withhold a competitor's generation from the marketplace.

The SMA test does identify large market share in generation. That's not what the pivotal quantity is necessarily about but there is an overlap between having a large market share and having questionable results under the

SMA test.

This helps identify not only the ability to engage in the kinds of withholding that are purely horizontal but also identifies the incentive to withhold true control of the transmission system and exclusion of competitor's generation.

Accordingly, any modifications to the SMA that you should consider should retain this ability to assess the overall market share and generation interests of the applicant.

In this area, I think I have to disagree with Dr. Pace and the other commenters who have suggested that native load obligations should be somehow taken out of the market share because it's precisely that generation that an applicant may be attempting to preserve high prices for, but protecting against the wholesale access of competitors through transmission control. With that I'll wind up and perhaps take any questions you might have.

MR. RODGERS: Thank you. Questions.

MR. O'NEILL: Can I ask if, what I heard you say was that it's the most profitable strategy. Not to withhold new generation from the market but to withhold someone else's.

MR. CORNELI: I don't want to quite jump that far. There is an assumption here which goes to the details about the relationship of retail regulation and the lack of retail regulation in the incentive a load serving entity might have, but if the assumption is that the Commission needs to be concerned about a market based rates applicant's ability to exercise market power, what I'm saying is, that ability is as likely, if not more likely to be affected by the applicant's capability to exclude competitors from the market, as it is to price up its own pivotal or otherwise important areas.

MR. O'NEILL: How do they exclude competitors from the market?

MR. CORNELI: By limiting their access to the transmission system through say, denying applications for firm transmission or making liability conditions associated with running, particularly generators more onerous than they need to be.

MR. RODGERS: Commissioner Kelliher.

COMMISSIONER KELLIHER: I had one question about the market share discussion. Generally, market share, in other context, other industries is defined in terms of sales, not capacity, whether you're talking about total capacity or uncommitted. Why in the electricity context is it a question of capacity rather than sales?

MR. CORNELI: Commission I think that's a very good question. I'm not sure that there needs to be a large difference except that sometimes capacity itself is part of the product that is sold. As some of the previous discussions pointed out, if somebody sells somebody else capacity, it's the right essentially to call on energy associated with that. That in and of itself maybe highly valuable, even though the amount of energy delivered is relatively low.

It might come at a time when it is essential to keep the prices low to keep the lights on. At least, in that perspective, capacity is actually a product that is sold and would be relevant.

MR. O'NEILL: Can I follow up on that question? If in fact in their supply margin assessment calculations some independent generator has a certain amount of capacity that includes them in the market and then in that three-year review, we see that he has been able to sell no where near that amount of capacity in the market, how fair do we cap the capacity the next time around?

Should we essentially, as Commissioner Kelliher suggested, go to the actual sales of historical commercial transactions to verify whether or not the capacity that we thought or assumed to be in the market is actually in the market.

MR. CORNELI: I think that would go back to the fundamental question of why do you want to know what the market share is? If the question is, are there other competitors available to come in at a price that would limit the ability of the applicant in this case to jack up prices somehow through some kind of withholding or other scheme, it seems to me the real question is not, was there as sale or not, it's was there the capability to make the sale.

The watchdog doesn't necessarily repel invaders by barking. Just the presence sometimes is enough to do that. Going back to what is, using a screen of market share information, it seems to me it's most useful in terms of identifying the potential and the incentive to exercise market power.

The check on that is not were other sales made, but could other sales be made? Which again relates to things like, is there really non-discriminatory transmission access. What is the basis cost for delivering that other product through things like through and out rates, transmission rates, tariff rates, and things like that, that will affect whether or not they really can be a delivered product at a particular price.

MR. O'NEILL: Even though in one analysis we assumed the competitor had lots of capacity markets, even though in the three years that follow the analysis, the competitor made virtually sales into the market. You would still count that person as a competitor in the market?

MR. CORNELI: Let me go to the example I raised and I think this would maybe apply to other types of barriers, shall we say to participation in the market. If that person was unable -- that independent was unable to participate in the market because the ATC levels were always very low, while the TTC levels were high and most of that ATC was going to the applicant or its affiliate, I would think you would probably want to say that there has been something questionable going on here that needs further investigation.

If, on the other hand, the reason that applicant has not made any sales is because their cost is $10 above, including the bases where delivered price is $10 above wherever the price has ever gotten to in those three years. It would seem to me you'd say, well great, they're there already to deliver and able to deliver if the prices start to get out of control.

MR. O'NEILL: So you're willing to accept the fact that very high-cost units that are hardly ever in the market should be counted as part of the market?

MR. CORNELI: If they can access the market, if the ability to deliver goods is there. It seems to me that makes sense.

MR. RODGERS: Thank you very much Steve. We appreciate it. Why don't we now go to our open microphone session. As I mentioned at the outset, there are two microphones at the bottom of each side isle. If there is folks in the audience that would like to come and ask a question or make a comment, please feel free to do so.

(No response.)

MR. RODGERS: Why don't we go ahead. Cliff, did you have one question?

MR. FRANKLIN: If I could. It's to Mr. McNamara. In MISO, I thought Commissioner Kelly asked an interesting question and I want to kind of expand on it about markets breaking apart.

In MISO, you have pretty good reserve margins, correct? Over 20%?

MR. MCNAMARA: Yes, but it varies from region to region.

MR. FRANKLIN: But if you were to look at MISO's overall control area, it has a very good, healthy reserve margin.

MR. MCNAMARA: Yes, with those caveats, yes.

MR. FRANKLIN: Have you found, despite that large reserve margin, that there is, during the summer months and high load periods or whatever, can markets break apart in load pockets. Is it pretty predictable? That's the first question. The second question, can it do a lot of damage to those rate payers in that market, even if it breaks apart dramatically for a short period of time?

MR. MCNAMARA: Yes they can break apart because they'll break apart whenever there is a constraint. That's why I said the accompanying caveat with regard to the 12%. It's not necessarily true that the reserve margin is in the appropriate place where it breaks apart, so yes.

And in terms of predictability, I expect that when we open with LMP, we'll see different patterns of how constraints arise. Whatever we've leaned in the past, there is a degree of predictability to it with regard to how the plants are running, but I think when you go to LMP, I'm not going to say that I'm going to predict the constraints the first or second year of operation. I think things have settled down. It's been my experience in other LMP markets, things by and large settle down and they -- I think commercial solutions are very robust and people have contract positions out there once they figure out what's going on.

I think there is a degree of predictability but certainly not in the first couple of years. Every LMP market has changed over economics when it has changed. Ultimately to the extent that someone is unhedged in that environment, yes, there is potential for damage.

But again, I think one of the things that has to be asked is, if people should be hedging themselves in these markets.

MR. FRANKLIN:  From a 30,000 foot perspective, how does the MISO, I guess you get substation loads and you get generation, and you can do everything at a time but from an analysis point of view, how would somebody go about getting the simultaneous input capability of some place like Cleveland or some place like Pittsburgh, or some place like Cincinnati that's in the MISO's area?

MR. MCNAMARA:  Now or in the future?

MR. FRANKLIN:   Historically, how would somebody go about getting simultaneous import capability in a load pocket?

MR. MCNAMARA:  You can get a rough approximation. You can get pretty close to it by control area but by specific are within that, it would be very difficult.

MR. FRANKLIN:  Thank you.

MR. RODGERS:  On behalf of the Commission, I'd like to thank all of our panelists.  We very much appreciate you giving us your time and your thoughts to help us work through these issues.  We will reconvene at 1:00.

(Whereupon, at 11:45 a.m., the conference was recessed, to reconvene at 1:00 p.m., this same day.)

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A F T E R N O O N   S E S S I O N

(1:00 p.m.)

MR. RODGERS: If I could have your attention please. Why don't we go ahead and try to get started. Good afternoon. This session is the second panel on our discussion of the appropriate interim generation dominance screen and the appropriate mitigation associated with that.

The focus of this panel is on the appropriate screen itself. We will talk about some specific topics in this session that include how to determine the appropriate capacity to use in the screen. How to determine the opportunity demand under the wholesale market share screen. Which approach is preferable for an interim screen, a pivotal supplier screen, a market share screen or some different alternative altogether? Whether the analysis should be applied on a monthly basis or an annual basis or some other time increment? And whether and how to capture generators ability to withhold on non-peak days over sustained periods of time.

I'd like to introduce first of all this afternoon, Bill Marshall, the Vice President of Fleet Operations and Trading with the Southern Company. At the table with Mr. Marshall this afternoon is Rodney Frame, the Managing Principal of the Washington office of Analysis Group. Mr. Frame was asked by Southern Company to appear.

Though he will not give a prepared statement on this panel, he is available to help answer questions related to these matters when we get to the Q&A session.

Mr. Marshall, welcome. We look forward to hearing your remarks.

MR. MARSHALL: Thank you very much. Thanks for the opportunity for us to come and present our views to you today. We appreciate that.

We are part of southern Company as you said, my employing company is Southern Company Services. That's a service company under the Public Utility Holding Company Act. We provide services into the operating company subsidiaries of Southern. That would be Alabama Power, Georgia Power, Gulf Power and Mississippi Power, Savannah Electric and Power and Southern Power.

Our responsibilities are for the economical operation of our generating assets to serve our retail and our wholesale customers which today comprise about 35,000 megawatts of load or firm load. We have then about 40,000 megawatts of generation that's comprised of coal, oil, gas, nuclear, and hydro facilities.

I'm also responsible for our activities in the short-term market. These activities are important to us and to our customers because they minimize the cost to serve Southern's retail customers. We purchase power when it's more economic for us to do so than we can produce it and if we have surplus power, we'll settle that into the market as well.

We make these sales or revenues from them, go to reduce the cost of service to our retail customers. As kind of a first matter, I'd note that we submitted comments on January 6th in response to the notice of this technical conference and we included the affidavit of Mr. Frame, who is here on my left. So, there is a lot more detail obviously than I can cover in 5-7 minutes in that particular filing. So we presented in more details our views of the screens of the mitigation measures and the alternatives therein.

I'd like to address the market screens that the Commission is considering to assess generation dominance when it considers applications for market based rates. Before I do that, I'd like to talk about three basic points just for emphasis.

First, the Commission should emphasize that not all generating capacity is available to compete in the spot market. Utilities like us that are in areas that are now entered in on retail restructuring, retain obligations to serve a retail load at regulated prices and we have to dedicate sufficient generation to meet that obligation. As well, we have to satisfy our firm and wholesale commitments as well.

The priority afforded these obligations is well documented. We have an inter-company interchange contract that governs how our companies interact with each other. It's been on file at the Commission for a number of years and it really provides that the operating company's firm retail load and our firm wholesale obligations have a first priority call on our generating capacity.

State simply, this capacity is not available to the short-term market. We've already sold it. It's already committed. Any utilities without this contractual obligation do not have an incentive to raise prices in the wholesale spot market by withholding this kind of capacity.

If a utility was to do so, it might increase the spot prices but that utility would be purchasing, in other words, buying back the withheld capacity at increased prices in order to beat its obligations since the prices as charged are either fixed by regulation or are certainly subject to regulatory scrutiny. The utility would not have any incentive to engage in that kind of behavior.

Measuring generation dominance. The Commission must take into account the impact of firm obligations and focus only on the uncommitted capacity that can be used to make additional spot sales. Any test that fails to do that is fundamentally flawed.

The second point, the Commission should consider the amount of load that would be served through this competitive market. If there is a reasonable choice of supply alternative, then it should not matter if one supplier has a very large market share.

For example, we might be interested in purchasing 100 megawatts. If one potential supplier had 500 megawatts and there were another four that had 125 each, that would be 1,000 megawatts. The largest supplier would be 50% of the market but wouldn't be able to exercise market power because there is competition for that 190.

In other words, the size of the market matters so the Commission should avoid screens that only measure relative size instead of market power. As we'll discuss later, we believe that a properly structured pivotal supplier test would avoid this pitfall.

The third point, the Commission should be very cautious regarding the adoption of mitigation measures. Mitigation measures would have to be carefully crafted to avoid adverse impacts on retail load. If a utility is required to sell at below market prices, in other words at cost based prices or something less than the market, then retail customers would be harmed by that.

With this background and those three points, I'd like to comment briefly on the screens discussed in the paper.

To start with the SMA test which was announced in 2001, we believe that's flawed because it fails to recognize that much of the vertically integrated utilities capacity is committed to serve the firm obligations that I've discussed.

In response to criticism of that screen, there is a new measure called the Capacity Surplus Index. Although this test has some differences from the SMA screen, the original SMA screen, it essentially asks the same question, that is, can the load in a controlled area be served without the applicant's generating capacity?

In nearly all cases, the answer would be no for utilities with retail service obligations. As explained earlier, this does not accurately reflect the company's ability of incentive to exercise market power. The paper also references two market share screens; the Limited Competing Supplier Screen and the Wholesale Market Share.

The Limited Competing Supplier Screen looks to us like two parts. One is applicant's share of total capacity, the other is the share of uncommitted capacity. We think again this test fails to accurately assess market power, at least a part of the screen ignores the effect of retail and wholesale obligations and because both parts only measure relative size.

In the last screen, the Wholesale Market Share

Screen is a similar test, but it considers only the applicant's share of uncommitted capacity. While this difference is substantial, the test is still flawed because it focuses only on size rather than considering the amount of load to be served.

So we would encourage the Commission to explore the methods that would address these concerns. One measure we believe would be workable is a modified SMA test. This modified SMA screen focuses on the wholesale load that is subject to competition and the applicant's uncommitted capacity to determine whether it is a pivotal supplier in the short-term market. We provide more details of this approach in our comments that we mentioned earlier.

This concludes our opening remarks. Mr. Frame and I are ready to answer questions you may have.

MR. RODGERS: Thank you very much. Questions?

MR. LARCAMP: Is it a fair statement that Southern believes that a modification of the Commission's existing or pre-SMA test is appropriate?

MR. FRAME: That's not correct. A modification of the SMA test would be appropriate.

MR. LARCAMP: I understand. I'm just trying to make sure that I understand the corporate position is that some more specific measurement than what's reflected in the prior hub and spoke test is an appropriate undertaking for the Commission.

MR. MARSHALL: I think it is, yes.

MR. O'NEILL: Can I ask a question? In your modified test, what are your assumptions about how to count the competing generation. More specifically a lot of generation in and around your market or your control area doesn't have access to markets. Would you define that calculation for generators who can't get access to the markets that you serve?

MR. MARSHALL: By not having access are you talking about because of transmission limitations?

MR. O'NEILL: Yes. It's fundamental to how you calculate the number of competitors is whether or not they can get access to the market. If they can't get access to the market, they can't be calculated in the test.

MR. FRAME: I think the test that we would propose would be as the SMA test is but using uncommitted capacity.

MR. O'NEILL: I don't care about your uncommitted capacity.

MR. FRAME: If I may continue, then you would look out to the interconnecting control areas, use the TTCs or the lesser of the uncommitted capacity.

MR. O'NEILL: What about the generators in the control area?

MR. FRAME: There is no question that if for some reason it's bottled up and can't serve the market it ought not to be computed.

MR. O'NEILL: So we should modify the test?

MR. FRAME: I'm not certain of that. I think that you have to look at what we're talking about first of all not as a test, but as a screen. I think we're talking about designing a screen that would be applied broadly across a variety of circumstances across the country. Not a definitive test, but a screen. I think if you can have a screen process across such a broad area, you always have to recognize that the screen may not be perfect in all cases.

I think we've heard a lot of what about this, what about that, in the panel this morning. You probably can't design a screen that takes those into account for all times and places. That stated, if these are important factors, they have to be taken into account at some stage, either at the time that the filing is made or in a stage 2 analysis that points out why the plain vanilla screen may not be applicable in this case. If there are real concerns, take them into account.

MR. O'NEILL: So the answer to my question is?

MR. FRAME: The answer to the question is the one I gave you; take them into account if they are real. I'm not certain in all instances we will do that as part of a screen.

MR. O'NEILL: So if these generators have made requests for transmission and have been able to get it, they shouldn't be counted in the market?

MR. FRAME: I'd need to know the facts. What generators and what is the request for transmission? If the transmission is from inside the control area to some point outside of the control area, that doesn't sound like what we're talking about when you talk about serving control area load.

MR. O'NEILL: If they can't get transmission to the market they want to serve, should they be counted in that market?

MR. MARSHALL: Can they get transmission into the local market or -- I think Ron is saying if they can't get out they may still be available to the market within the control area.

MR. O'NEILL: The question is, is that a fact pattern and we should take into account the conservative test?

MR. FRAME: Maybe I'm not following you. If they are available to the local market, they should be included in that local market.

MR. O'NEILL: You name the market and if they can't get transmission capacity to it, should they be counted in the market?

MR. FRAME: No, they shouldn't be counted.

MR. O'NEILL: Thank you.

MR. BARDEE: I'd like to ask you briefly about the remarks you made on incentive. If I understood it right, I think what you were saying was that the utilities either had fixed rates or their rates are subject to scrutiny, therefore they don't have an incentive to drive up prices.

Do you know of the Southern operating companies, are there purchase power costs flowed into the fixed rate as a credit against the cost of service or are they treated in an adjusting clause?

MR. MARSHALL: For the most part, an adjusting clause so it would need regulatory scrutiny.

MR. BARDEE: If you had unregulated generation within the same market for which the profits went to shareholder, you in fact would have an incentive, but it would be balanced in your view by the risk of the regulation catching any misbehavior?

MR. MARSHALL: Let's go back a little bit then and make sure that I understand what your point is. The first thing is for our retail load, we have an obligation to serve and then for our longer-term firm wholesale, it's already sold, so it isn't available to go into the market, so we can't take that to market.

The part that we can go to market with, it's a matter of whether there is competition and whether we are a pivotal supplier or not. If we're not, there is competition and I would think there would not be a problem for us or if we were purchasing from somebody, I wouldn't be worried about them either.

MR. LARCAMP: I think the question is, when you are in charge of selling Southern Company Services, any excess that is available from either your native load after your native load or wholesale requirements have been taken, are 100% of the profits from those off-system sales credited back to either your native load customers or your wholesale requirement customers? If the answer to that is no, then you have an incentive.

MR. MARSHALL: It's all credited back and there are regulatory mechanisms within the individual state commissions that decide if there is a sharing of that or not, but it's all credited. If I'm understanding you right, it's all credited.

MR. LARCAMP: For all generation that Southern Company Services sells on behalf of any Southern Company subsidiary, those off-system sales are credited back?

MR. MARSHALL: Let me be sure that we're clear on this. When we make a sale in a short-term market, the proceeds of that sale are allocated to each one of our companies. One of those companies is Southern Power, which is not a traditional state jurisdictional type of company so that company gets its percentage of that based on size, it's based on what we call peek period load ratios. So it gets allocated its piece of that, that is not subject to state's scrutiny, but it doesn't do anything in the short-term market on its own, can't do that.

In other words, our company interchange contract says that if we do transactions of one week or less, they are for the pool, not for any individual company.

MR. LARCAMP: What's the relative percentage of the profit for Southern Power versus the five operating companies?

MR. MARSHALL: It would be in the neighborhood of 7% of the system.

MR. LARCAMP: So roughly 7% of all system sales are allocated back to Southern Power and the balance is subject to some sort of credited mechanism with respect to one of the five operating companies?

MR. MARSHALL: That's right.

MR. PERLMAN: If I can follow up on this a little bit, not to beat this horse too much to death but you said there was some sort of sharing mechanism. If it was credited back, I would assume the state would like to get you the highest price you possibly can so that it would be the largest credit back to the retail customers. And, if you were very, very successful, you may be able to keep some of that revenue, is that correct?

MR. MARSHALL: The Commission would expect us if we're selling to sell at a price that's profitable to us, if that's what you're saying. And if we're buying, they expect us to buy at a price that would be saving us money. I think that would be their incentive.

MR. PERLMAN: The higher the price, the bigger the credit. Is there some sort of sharing where the company may be able to keep some of the revenue if it be some kind of bogey, or something like that?

MR. MARSHALL: I'm not sure that that's the case. It all goes back to the states. I'm not as familiar with what individual states, what they do with that.

MR. PERLMAN: I have a different question as well. Getting off this topic a little bit, relating to something Mr. Bittle said this morning. He was talking about the idea of taking the retail obligation and subtracting that and doing the analysis.

He effectively said if you want the claim that's taken effectively to serve the retail customers, you shouldn't be able to take the entirety of that and sell it in the wholesale market at market based rates. Maybe you should have some sort of dichotomy, where there is some element of your generation base that should be, in effect, capped to a charge, some sort of cost base rate, and then that increment that's in addition that shows up from crediting or something like that, would be the market based rate. Do you have any reaction to that? Do you think that's workable?

MR. FRAME: It strikes me that what you're talking about would not be a pro competitive thing to make that segregation of generation, in effect remove some generation from the wholesale market. That sounds like something that would be likely to drive up prices, not to lower prices.

MR. PERLMAN: I would not think you would say it's not permitted to sell into the wholesale market, it would just be subject to some sort of cost based or price cap with some other segment that was able to be sold without it, with a similar cap. I can't speak for him, but that was my understanding of it.

MR. MARSHALL: I'm not sure I understood it. If we are not by the test, I'm not a pivoted supplier in the market, then we don't think there should be no mitigation to that.

MR. RODGERS: Could I just ask one question, then I think we're going to try to move on to the next panelist.

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Just to clarify the portion of your profits from off system sales that go back to retail customers, I understood from page 2 of your affidavit, from December '01, that Georgia Power Company and Gulf Power Company, that not 100% of the off system sales profit they made do in fact go back to retain customers. Only I think you said 69% and 77%.

MR. MARSHALL: I think Gulf has changed since then and it all goes back. My point is that it is subject, whatever the state regulators tell us to do is what happens with that. So it's their call, it is theirs to have. If they that say we can share in that, then they do it. Some do and some don't.

I think in Georgia, to the best of my recollection, that's correct.

MR. RODGERS: Why don't we go on to our next panelist and maybe come back and revisit some of these issues later. Thank you very much both of you all for your helpful comments.

Our next panelist this afternoon is Dr. Steven Henderson, Vice President of Charles River Associates. Dr. Henderson has been asked to appear today by Entergy. Welcome Dr. Henderson.

DR. HENDERSON: Thank you very much. I

appreciate the opportunity to speak with you all. I'm an economist at Charles River Associates. Since leaving FERC, I'm a practitioner. I've been filing this interim market screen now probably in dozens of cases and before that, probably dozens of hubs and spokes.

I guess I don't have three points, I really only have one point that I want to make. This is about the native load issue and I'm glad to harp on it. You can throw spears at me if you want to because I really believe what I'm about to tell you. I really think there is just one issue and it's still the issue and it's unresolved. If you have problems with the native load issue, I think we just need to get it out on the table and explain what they are and address it.

That is to me the overarching issue in the case, is how to account for native load commitments and long-term contractual commitments in the wholesale market. Also, in my view, any screens got to be able to reflect the realities of supply and demand in the market, including good retail competition, I'm sorry, retail regulation and retail regulation that brings native load into consideration.

A screen that doesn't reflect that risks giving false positive indications which in the long run will undermine wholesale competition and harm consumers. A lot of other interesting issue, kind of screen design issues would be in some sense more fun to talk about. I'd be happy to do that in the Q&A monthly versus annual and outages, operating reserves and so on. All of those things are interesting and important but I really think the native load issue is the critical one here.

I can recall discussions, arguments with some people at this table here and before coming here at NRRI where we'd make these general kinds of comments that exercising market power on behalf of a native load is nonetheless exercising market power.

In the abstract, that's certainly got to be some specialized circumstances a true statement, but it truly is not the end of the story.

I had always thought when we were talking about that, that we were talking about our utility exercising market power in a wholesale market after fulfilling its native load obligations.

That is, after it has done that, there may be some participation in the wholesale market and in kind of using the excess generation or affiliate generation in that wholesale market to exercise market power.

If it does that, that's a problem. And I would certainly agree with that and that ought to be the focus of the inquiry, if the utility's participation in the wholesale market is above and beyond its native load obligations. And it seems to me over the course of time here that this has become, I would have thought, kind of clear.

If a utility is a net buyer, and there's examples of that that you all have had to deal with -- if the utility is a net buyer, they are clearly not in a position of wanting to exercise market power so as to increase price. That would just shoot themselves in the foot. They'd have to end up paying more for their other purchases that they have to make and there really isn't any story that you can tell about the way --

MR. O'NEILL: Do you mean net seller?

DR. HENDERSON: No, as a net buyer so that they have more demand in generation.

MR. O'NEILL: Okay.

DR. HENDERSON: As a net buyer so they have more demand in generation. They may be interested in making prices go down, but they wouldn't be interested in making them go up so you might have a utility that has 8,000 megawatts of generation, but only has 7,000 megawatts of load. And it's got to buy 1,000. They don't want prices to go up. They wouldn't withhold any of that 7,000 megawatts of generation that they have in order to make prices go up.

They are net buyer. They would, if anything, want to see lower prices, not higher prices and all I'm saying was you've dealt with circumstances where people are in that situation and that is the case for at least some utilities.

Entergy is a net buyer at least at peak. At off-peak times, I'm sure they have some surplus to sell. But as you are aware here at the Commission, they're trying to use the market to get some additional resources.

To me all that says is that the unbiased starting point for the analysis seems to me to be the utility's uncommitted capacity, that which is above and beyond its native load obligations and its long-term commitments.

If you're going to bias that one way or the other, maybe there is a some story there but I haven't heard it yet. I've listened to the panelists and so on. I haven't heard a compelling story that says, if I've got 8,000 megawatts of generation and 10,000 megawatts of loads so I'm a net seller now for 2,000, well I might want to withhold, you know, maybe 400 in order to raise the price for the remaining 1,600.

But there isn't anything about that activity that I can tell that really affects the 8,000 megawatts of basic underlying native load obligations. You come at that analysis using standard economic theory and you'd say the 8,000 megawatts of native load just simply ought to be taken out of the market and go from there and see what kind of market power they have to exercise with that which is in the market above and beyond their native load calculations.

I guess I think that cost base regulation effectively mitigates the ability and incentive to exercise horizontal market power. The ability is taken away because of direct regulatory oversight and the incentive is effectively eliminated by the fact that you can't get a higher price.

If the price goes up, the native load is nonetheless regulated. You can't charge at a higher price. So the incentive is taken out of the market by the obligation basically to sell.

So I think the correct economic analysis would remove all load that subject to cost base or fixed long term prices from the market and also remove the associated level of generation. That would be the starting point for the analysis and if we want to talk about possible reasons why that's not exactly the right measure, that would be fine.

But you ought to think of this utility that 8,000 megawatts of capacity and 10,000 megawatts of load. To me it says you ought to use 2,000 megawatts of uncommitted capacity. I haven't seen anything that says you ought to use its entire 10,000 megawatts of generation that it has.

With that I think I've teed up the issue enough and beaten it enough. I'll stop and just tell you that I appreciate the opportunity to speak to you.

MR. O'NEILL: I hope you are not surprised, but I agree with you. Now let's move on.

DR. HENDERSON: You and I usually agree.

MR. O'NEILL: We've made the numbers as small as possible for the utilities serving native load. Would you similarly be much more careful about competitors that we include in this index? That is right now we include competitors that as far as I can tell, can't get access to the markets and have tried. Yet we include them in our supply market assessment test. Should we get them out of that test?

DR. HENDERSON: If I knew and had concluded that they do not have access to the market, I would certainly agree that they shouldn't be in the market. It's a little unclear to me how I'd find that out.

As Ron was saying, if we do that automatically. I'm a simple practitioner here. I take publicly available facts and combine them and present them to you all and let you all make the decisions. To the extent that I fall short of capturing everything, people have the opportunity of coming in and saying, Henderson fell short.

MR. O'NEILL: One publicly available fact is generating operating limits, which on some occasions, severely limit the capacity that would be available in the market. Would you start lift generating operating limits?

DR. HENDERSON: That would certainly be something that should be looked at. I couldn't tell you right off exactly how I'd treat it. I haven't looked at it in detail.

MR. O'NEILL: If they can't generate above a certain level, how can you count anything above that level in the market?

DR. HENDERSON: I don't now that I have a full -- I don't know if I can engage in an intelligent conversation with you because, when I was doing the cost benefit study, the Entergy folks were trying to explain to me how the generating operating limits operated and I was going back and forth with them. So I don't know that I have a full appreciation for it.

MR. O'NEILL: So we know how to fine-tune the incumbent utilities generation to make it look very small but we're really nervous about fine-tuning.

DR. HENDERSON: I'm not nervous about it. I'm not nervous at all. I just don't know exactly what to do.

MR. O'NEILL: Would you include that in your next analysis?

DR. HENDERSON: The reason is -- yes if it's appropriate. The reason is, as best I understood it, there was an ability to participate in the market on a non-firm basis beyond the generating operating limits, but I probably have that wrong and I'm speaking out of turn.

I haven't prepared for it but the generating operating limit seems to me, as best I understood it at the time, and I probably should go back and inquire further about this, since it's my client that we're talking about here, I should probably know the answer to this, but I don't.

The generating operating limit, I thought, has a somewhat longer-term flavor to it in terms of the limit that it represented and if there was an ability to participate in a very short-term non-firm market beyond that, but, you know, subject to check, I agree in theory with what you're saying.

MR. LARCAMP: Just one. In terms of your example, Steve, the 8,000 and the 10,000. The 2,000 that they're purchasing normally, there's a dollar-for-dollar pass-through. Is that your experience?

I guess what I'm trying to understand is there is an incentive to sell all of the eight that may be rate-based, even if there are cheaper availables in the competitive marketplace? When you buy, you get a dollar-for-dollar pass-through of your purchased power costs, but you don't make a profit -- as a vertical integrated utility owning that generation, if the reverse is that only 6,000 of yours gets to run over time and you've got to purchase four, then you're sort of in a negative incentive, aren't you, with respect to that, too?

MR. HENDERSON: Let me make sure I have the hypothetical correct. The two represents --

MR. LARCAMP: The difference between 10,000 load and 8,000 in your rate base. You said you had no incentive to try and change anything but, in effect, the best market price for power for the two --

MR. HENDERSON: In your example, this is really a net --

MR. LARCAMP: Your example, the eight and the ten --

MR. HENDERSON: I had it reversed. I had one that had 8,000 megawatts of generation.

MR. LARCAMP: That's my example.

MR. HENDERSON: 8,000 megawatts of load and 10,000 megawatts of generation, so here is a net seller for two. But you want to change it now so it's a net buyer --

MR. LARCAMP: I thought your answer originally was that if you were a net buyer, you have no incentive.

MR. HENDERSON: That was my eight and seven example. Okay.

(Laughter.)

MR. LARCAMP: So a thousand to purchase power. I'm just trying to understand that statement in a world where purchased power clauses allow you sort of a dollar-for-dollar recovery but don't have necessarily any profit potential. You do have the incentive, don't you, so make sure that all of your rate-based runs, even if cheaper power is available from competitors -- I mean, we're trying to get plentiful supplies at reasonable price for everybody. So I'm just trying to understand that example where I'm a net purchaser and what my incentives are for that to hold true. I do have the incentive to make sure that everything I own is dispatched to me, because if it's not over time I'm going to probably be found imprudent if I don't buy from the cheaper alternative available in the competitive marketplace.

MR. HENDERSON: I think certainly the short-term incentives are to buy as cheap as possible. If there's -- I think you're saying there may be some longer-term incentive for a utility to try to use its own generation, even if it were perhaps not the most economical. That may or may not be true. I don't have any evidence of that one way or the other. I don't know how you'd work that phenomenon, even if it were true, into a horizontal market screen.

MR. O'NEILL: Can I extend Dan's example a little bit further? You're now a net buyer in the market and you're buying from generators in your service territory. Is there an incentive to block access of those generators to other markets so that you can negotiate a very cheap deal?

MR. HENDERSON: Some theoretical incentive. There's probably some incentive. I had always hoped that the Commission had effectively removed the ability to do that through various and sundry transmission access requirements. Certainly going to the outside -- that would be something that would be on the OASIS and presumably pretty checkable.

The other issue you're talking about, which is the generating/operating limits type of issue, which involves access internally to a control area. I'm not 100% familiar with exactly how this works, but it's not exactly an OASIS-type product. So there's -- it may be now an energy -- I may be speaking out of turn, I haven't kept up with this because I think the generator operating limits are posted on the OASIS. But in any case, it's not getting transmission service to another system, it's internal to the system.

MR. O'NEILL: Suppose we observed a vertically-integrated utility buying cheap from independent generators in their service territory, then selling generation out of their service territory at significantly-higher prices. What should we conclude?

MR. HENDERSON: That's something that you should look into.

MR. PERLMAN: I have one simple clarifying question: when you credit the retail service obligation against the capacity, how do you calculate the retail service obligation? Is it the annual peak or is it something different?

MR. HENDERSON: I'd be inclined to say if we are really talking about a horizontal screen here, subject to additional review and getting into all kinds of other issues, I'd be inclined to say do it on the annual peak, yes. Unless you had some reason to think that the market power problems in the area are somehow kind of exacerbated or a little higher in off-peak times. I don't know that there's a large need to do the calculation in off-peak periods, but there's nothing to prevent it being done. If you wanted to look in off-peak periods, you just take a measure of off-peak native load and subtract that from some appropriate capacity measure.

MR. PERLMAN: So you could make a judgment as to what you think might be representative as to what level of generation would be available to compete in the wholesale market. You wouldn't have to be locked in to the annual peak.

MR. HENDERSON: You wouldn't have to be locked in to the annual peak if you think there's some compelling reason to do seasonal or monthly. You can do that. As a simple practitioner here, I'm trying to think about the kind of problems you're going to cause me if you -- this is in terms of pulling the analysis together. From the applicant you can get probably a sequence of 12 monthly peaks. That should probably be decently straightforward and could make this calculation of uncommitted capacity for the applicant. On a monthly basis or a seasonal basis, that's probably not too hard to do. Getting comparable data for everybody else, though, may be somewhat problematic.

That's why I think the peak is probably going to be the most reliable measure unless we have better information. But there's nothing in theory -- or mysterious about making the calculation; if you have the information, you can make the calculation.

MR. LEE: I have one quick question. My question is about the uncommitted capacity. Basically the question is very simple: how to quantify uncommitted capacity based on this morning's discussion. And also, some recent studies show the uncommitted capacity is not really a stable number; it's not a constant number. It's a variable. Because there's a study that shows IOU would seek to convert commitment capacity to the uncommitted capacity many hours a year. So if this is a moving target, how can we quantify that is my question.

MR. HENDERSON: Just to clarify, are you asking about long-term contractual commitments and how those get converted and they stop and they start and that kind of thing in the wholesale market?

MR. LEE: Yes.

MR. HENDERSON: I heard some of that discussion this morning also and thought it was interesting. My quick reaction is it does seem to me that long-term contracts is something that you may need to clarify. Right now we have kind of a standard: a long-term contract is something which is when there are more, yet we have a three-year screening period. There is a bit of a disconnect between the two. What do you do?

My first reaction would be Well, okay, that's true for the wholesale market that we have long-term commitments, those come and go, and it's hard to keep up with that. Once again, working for an applicant, you can pretty well sort out what their long-term contracts are but you pretty much don't know what the rest of the space looks like. But you do know what regulated retail load looks like. That grows pretty regularly, pretty steady. You can take that out if you want to make an analysis.

I thought we were talking about a spot wholesale market, horizontal market screen. So taking out long-term wholesale commitments would make sense. But if you think there's some problem in the longer-term wholesale market, then for us to take out retail regulated flow, set that aside, now you've got a market where you can say This is that which is available, both for long-term and short-term wholesale things and you can analyze that. That might make some sense. I didn't think that was the point of this inquiry, but it's kind of like an additional review step.

Once again, if after you make -- you set up the screen to do one thing and if you hear that there's another problem, you say Okay, I now need to look further into that. I could imagine doing some sort of screen for a longer-term wholesale market where you still made the kind of correction that I'm talking about where you're only correcting for the retail portion of it. Take the retail obligation out.

MR. RODGERS: Steve, in terms of taking capacity used to serve native load off the table in terms of not counting it towards the applicant's capacity -- and that is your position, right -- would it be fair to say then that the Commission should conclude that the applicant should not be allowed to make any wholesale-market-based rate sales from those units to which they are devoted, in your view?

MR. HENDERSON: That's not how I think of it at all. These utilities have a portfolio of units -- in my example, let's see, what did I have? I had 8,000 megawatts of generation, maybe 7,000 of that is regulated and another thousand is owned by an unrelated affiliate. When we do these analyses, we throw together all of the capacity: affiliated, unaffiliated, regulated, unregulated. That's what I do. So I have 8,000 megawatts, and I guess I did have 8,000 megawatts with load is I think what I had before -- and I apologize -- and 10,000 megawatts of generation.

So the 10,000 megawatts of generation is made up of regulated and unregulated resources. You get the right answer if you just subtract out the 8,000 megawatts of regulated load from all of that capacity. What remains in the market is 2,000 megawatts of capacity.

And it really doesn't make any difference to me as market power analyst whether that's a unit which has been named as part of a regulated rate base or is an unregulated affiliate. That 2,000 megawatts of capacity that's in the market, 500 of it might be regulated and 1,500 might be unregulated affiliate. It doesn't matter. It ought to be the 2,000 megawatts of uncommitted capacity.

I add up everything as a portfolio kind of analysis, add up everything, whether it's affiliated, unaffiliated, regulated or not. But then subtract out the load for which they're not going to be able to raise the price on.

MR. RODGERS: But the amount of uncommitted capacity is varying over time. So my point is by assuming that all of the capacity used to serve native load at the time of the peak somehow shouldn't be counted in the equation because it's somehow not available for meeting wholesale needs, I'm not sure -- it seems to be overly generous to the market-based rate applicant I guess is how I'd put it.

MR. HENDERSON: Remember, what we're taking out is the load.

MR. RODGERS: And you're taking out the capacity that's used to serve that load and not counting that.

MR. HENDERSON: They might have 120% in their regulated rate base because of reserve margins and so on. But if you only take out 100% for the load, there's 20% that's going to appear as being in the market.

MR. RODGERS: Okay.

MR. LARCAMP: You won't take out the reserve requirements?

MR. HENDERSON: Good point.

MR. LARCAMP: It's 20%. It's 15- or 20%. It's a big number.

MR. HENDERSON: If you're going to do a pivotal supplier test and you want to include operating reserves, that makes sense to me. That would be a number like 106% or 105%.

MR. LARCAMP: And we wouldn't want you to sell those operating reserves because they're available for an N1 contingency.

MR. HENDERSON: Right.

MR. O'NEILL: Steve, I mentioned this morning that I had some simple spreadsheet models upstairs that showed if I had that 8,000 megawatts of generation, I could dispatch it in a certain way to block my competitors from the market. What would you do and how would we detect that?

MR. HENDERSON: I assume the models you refer to are the ones that force power down the line in order to force a competitor off --

MR. O'NEILL: Yes.

MR. HENDERSON: Once again, I thought we were talking about horizontal market screens.

MR. O'NEILL: It is a horizontal market screen because it depends on how you could the competition. As we develop the screen, we have to not only count the competitors, if the competitors don't have access to the market by virtue of a dispatch that the vertically-integrated utility can execute, then should we could that entity in the market? I'm not talking about trying to raise the price of transmission or anything like that. I'm asking how do you count these people who are blocked from the market?

MR. HENDERSON: If they're blocked from the market, they shouldn't be counted, I agree with you.

MR. O'NEILL: How do we detect that?

MR. HENDERSON: The question is how do you detect that?

You're not going to detect that, I don't think, with the kind of horizontal screen that we're talking about here. You're talking about something that requires some sort of power flow analysis, which is well beyond -- I mean, it's two or three stages of warp speed beyond what we're talking about with this screening analysis. And I have such simple spreadsheet models myself. But I haven't found a real-world application for them yet, and I know that that exists in theory. I can make it happen, too. Maybe there is.

MR. O'NEILL: You don't think your client could make it happen?

MR. HENDERSON: I don't know.

MR. O'NEILL: Maybe the people to your right?

MR. HENDERSON: I have never asked that question. I think I know the specialized circumstances under which it can happen, and there are a lot of other transmission bottleneck problems that I think are more serious than that one.

MR. LARCAMP: What if a wholesale requirements customer came in and told us that they sought transmission service to buy from a competitor and they were denied? Should the Commission exclude on that basis?

MR. HENDERSON: The hypothetical is that somebody was denied service on the OASIS?

MR. LARCAMP: They came in and said Look, we're a wholesale requirements customer. These are the people you're trying to protect, Commission, from the exercise of market power because the states are protecting them from cost of service regulation, the retail customers from the exercise of market power and they said we went out to one of these guys and said we'd like to buy some power and, lo and behold, whether it was ATC or TTC available, the request was denied. How should we respond to that?

MR. HENDERSON: If you trust the system impact study, you trust the capacity, and the capacity is not there. If somebody else was using it, you could always look into it, if you think there's a bad actor involved. And if you find one, go after the bad actor. You know, once again, as a practitioner though I'd be very reluctant to be doing a routine horizontal market screen that assumes that people are bad actors to begin with.

MR. LARCAMP: I'm not assuming when someone comes in for market-based rates or a triennial update -- there's an opportunity for comment. If somebody comments and says Wait a minute, the test you're applying is not accurate because you're trying to measure the pivotal supplier, there are some facts you need to be aware of, is that how we detect that type of behavior?

MR. HENDERSON: You can certainly look into it. The most obvious reason for why service is denied is that service is just not available. They're just out. I don't have any more.

MR. O'NEILL: When you get that answer back, you can't count those people in the market. I mean, if service is not available to certain generators to serve certain load, you can't count those in the market.

MR. HENDERSON: Well, this gets back to using TTC versus ATC, I think.

MR. O'NEILL: Versus just being denied.

MR. HENDERSON: They're talking about an individual competitor being denied. There's TTC out there that is presumably being used to import whatever the competition that's being enabled by those on-going imports that are filling up the capacity. Let's say a thousand can be brought in. Well, a thousand is being brought in by perfectly legitimate rivals, let's say. Then there's another thousand who ask and are denied. I don't include those other thousand, I only include the thousand that get in over the TTC.

MR. O'NEILL: If we had a thousand coming in, I agree with you, it probably wouldn't be a problem. But when it's zero coming in --

MR. HENDERSON: ATC being zero wouldn't imply that TTC is zero.

MR. O'NEILL: Should we just actually look to the actual transactions to see if people are getting access rather than going to a secondary source?

MR. HENDERSON: I think you can always do that.

You can do that any time you want to.

MR. RODGERS: I have just a couple of other questions, then I think we're going to move on to the next panelist.

Steve, I wanted to clarify my understanding from reading your affidavit that you feel the SMA, despite its infirmities, would be useful and appropriate to use as an indicative screen -- not a definitive screen -- and if it were used in conjunction with another type of screen, such as a market share screen, is that correct?

MR. HENDERSON: I think any of these screens should be just a screen. If I had to choose one measure, I'd base it upon uncommitted capacity and I'd probably choose the pivotal supplier over market share. If you do both, then there's a question about what are you going to do if somebody fails one and passes the other.

MR. RODGERS: A follow-up question: as I understand from your affidavit, you generally believe the SMA as set forth originally is too strict or a screen that fails too many people, there's too many false positives, is that correct?

MR. HENDERSON: Yes, and that's because it doesn't account for uncommitted capacity.

MR. RODGERS: Yet you mention in your affidavit that if the Commission were to use that kind of test, it would be more appropriate to use it in organized markets such as RTOs or ISOs where there is retail access, rather than in traditional markets, where there is not retail access, is that correct?

MR. HENDERSON: That was a point I was making just kind of broadly. If the pivotal supplier test -- and I think the pivotal supplier test is fine if you adjust for uncommitted capacity in a traditional area -- but a pivotal supplier test sort of has a more natural meaning in an RTO/ISO where you have full retail access. You sort of understand in that context.

MR. RODGERS: I guess what I was trying to understand in my mind was, on the one hand you believe that this test is too irregular, it's going to turn up too many false positives, but then the best place to use it is in markets that have mitigation rules in place, that have constant market monitoring going on and that have greater market transparency than you have in the traditional markets. I was just trying to understand that.

MR. HENDERSON: In those comments, I was abstracting from all of those points you were making. I think I would agree with -- and if you think that those substitute for the screen, I can appreciate that as a judgment.

MR. RODGERS: The last thing I wanted to ask you about was on pages seven and eight of your affidavit. You mentioned that allowing an uncommitted capacity version of the SMA test would allow a utility failing an uncommitted capacity version of the SMA to propose a remedy such as by offering to divest some capacity or by taking other actions to reduce its uncommitted capacity. I'm wondering if you think that divestiture option that you set forth is a more onerous mitigation measure than what Staff proposed in the White Paper?

MR. HENDERSON: Sure it is. It's definitely -- I wasn't suggesting that you go down that path. The context that you're reading there -- and I'd have to go back probably and re-read my affidavit a bit -- I was making the point that if you use a total capacity measure you can easily come up with screening failures that -- you clearly would not be able to come up with a structural remedy for them, even if you followed the advice of your FTC brethren and sought a structural remedy. If you fail the total capacity -- if a utility with native load obligations fails a capacity screening test, you can't divest and solve the problem. You can't simply divest the generation, you have to also somehow divest your native load obligation. Otherwise, you're going to be required to serve somebody and you'd have no capacity. I think we appreciate the kind of problems that can come up with.

So my point was if you're talking about an uncommitted capacity and you had a utility that had 140% reserve margin and you deemed that somehow to be kind of 40 percentage points too much in excess of the native load obligation -- at least potentially -- you can imagine that they might divest some of that. But that kind of divestiture solution doesn't even work if you're failing a total capacity version of the screen. So it was just to juxtapose -- divestiture works, potentially works in this case but doesn't even begin to theoretically work in that case.

MR. RODGERS: Okay. Why don't we move on to our next panelist?

I do want to thank you very much, Steve, for your comments.

One final note on Steve Henderson: he mentioned several times in his statements today that he's just a simple practitioner. However, we on Staff, whenever there's great controversy surrounding the SMA test, we always attribute it to you, Steve.

(Laughter.)

MR. RODGERS: I think we said it was the last thing you did on your way out the door.

Anyway, thank you very much, Steve. I appreciate your comments.

The next panelist today is Michael Wroblewski, Assistant General Counsel for Policy Studies at the Federal Trade Commission.

Thank you very much, Mike.

MR. WROBLEWSKI: Thank you for the invitation to allow me to speak today and to bring an anti-trust perspective to the discussion we're having this afternoon. Of course, a disclaimer that I have to give before I start any talk is the views that I express today are my own and don't necessarily represent those of the Federal Trade Commission or of any individual commissioner.

I'd like to start out with five kind of higher-level introductory comments before giving some specific comments on the screens that were presented in the Staff White Paper.

It's interesting, we've had a discussion now for about an hour and 20 minutes and no one has really ever said what are we looking for? It seems to me we have to keep in mind what we're trying to assess through this interim screening before FERC starts its more fulsome proceeding looking at market power.

What we're trying to assess is whether an applicant has generation market power such that it can profitably raise prices above the competitive level such that no other supplier will supply the relevant market and then defeat that particular price increase. That's my first point.

Second point: remember the saying garbage in equals garbage out. I was unable to attend this morning's presentation but regardless of the preciseness of any particular test that we're talking about, if the geographic markets aren't defined properly and the number of competitors and who they are and what their actual market's behavior will be based upon what the price is they can sell into these markets, the results of any of these screens will be meaningless. As we know, varying demand levels require all the systems to operate differently, so that you have constraints in which outside supply outside the control area can't come in or, conversely, at possibly a lower demand level that supply could go out further other than the control area. So remember to define your geographic markets properly.

Three, a lot of remembering here: remember to look not only at possible unilateral exercises of market power -- which is what the pivotal supplier tests do -- but also the possible ease with which coordinated interaction or collusion with other suppliers can be facilitated by high concentration or entry impediments. The effect on customers of the exercise of market power either unilaterally or in concert with others is the same: they pay higher prices or output is reduced. So please don't focus just on unilateral exercises of market power.

Fourth: the preferred route for the interim generation power screen may not be to rely solely on one of the tests that you've put forward together, recognizing that each one has its problems. You may want to require applicants to pass all four and, recognizing that each has its own problem, by having multiple screens you will hopefully get a better picture of whether an applicant can raise prices above the competitive level or reduce its output.

Interestingly, you brought up the question, Steve, on what do you do if you pass one test and don't pass another test. At that point, you've kind of got a problem but FERC can then require the applicant to come in with a more detailed analysis on a confidential basis that has something like power flow information that shows where their transmission is being, through a simple model -- excuse me, not transmission -- if the deployment of generation is being used in a way to cause transmission congestion, so that you wouldn't have -- be able to count certain suppliers into the market.

The fifth point I guess I want to make -- and this is kind of from my ideal perspective sitting at the FTC in a policy office, not necessarily being on the ground --

not from what you-all have to face right now, but for the future, it seems to me that FERC may want to embark upon a course where it can begin to identify and collect data and to develop a model so that it can not only measure market concentration but can also simulate various market conditions such that you can identify really when a supplier has market power. Customers will be the losers if, several years from now, we are in the same place we are in today because of the data limitations that FERC is now facing. The idea is to get on the path that provides the confidential collection of more accurate data only in those cases warranting a more extensive look in order to make economically sound market power assessments.

Let me turn real briefly in the last minute or two to some specific comments on the screens put forth in the White Paper. First, the pivotal supply models, the SMA and the CSI, are both unilateral models. Neither of them look at coordinated interaction, so that's a problem, recognizing that you're only looking at what that one supplier does. It's not really looking at whether it's allowing suppliers to coordinate their activities with others.

Second, the discussion that we've had, I guess, for the last hour and a half or so, really when we're looking at peak data, we're only looking at one hour of one day; we're not looking at the other 23 hours of the day or the other days of the week or the other weeks of the month or the other months of the year. Recognize that what we're only getting is really an assessment of market power. Assuming that we've defined the geographic markets properly, for only that one hour, just recognize that that's what you're getting.

The third point I'd like to make about these pivotal supply models is that there's a conceptual problem with doing these assessments only at the peak demand period. It's important to recognize that peak demand periods may occur simultaneously across an entire region. In these circumstances, imports from adjoining areas which otherwise would be able to come into the market won't be able to come into the market; they're going to be serving the peak area in their area. So if you're kind of counting that in, that may not make much sense.

The suggested improvements that we've talked out in terms of considering possible planned generation outages or reliability standards, that will be helpful. I mean, the more you can model what the actual conditions that market suppliers face seems to make more sense.

Two comments on the market share screens, which are the last two that you-all presented in the White Paper. The market share screens are an improvement over the pivotal supplier in that they allow a look at coordinated interaction. If you find that one person or one applicant has a 25% share of a properly defined market but you realize that only two others have the other 75% or maybe one other has the other 75%, there's a higher possibility of coordinating their activities such that there would be an exercise of market power and prices would be raised and output would be reduced. So keep that in mind.

I think I have the same problems in terms of if you're only looking at one hour, recognize that you're only looking at one hour. If you're examining monthly statistics that are averages, remember they shave peaks and valleys. So you have some limitations on what you get out of the models based upon what goes in.

In conclusion, I'd like to say don't rely solely on one screen, look at a composite of the screens while recognizing the weaknesses in each. Allow the applicant that fails a screen to present additional information to FERC on a confidential basis to justify why it should be entitled to market-based rates. In the meantime, maybe get on a path so that developing a model in those circumstances where a more fulsome look is warranted, you'll have the ability to do so in the future.

Thank you. I appreciate the invitation to speak, and I'll try to answer any questions that you may have.

MR. RODGERS: Thank you very much, Michael. We appreciate that.

Questions?

MR. LARCAMP: If we have a problem and they submit confidential data, ultimately the courts are going to require us to demonstrate with non-confidential words in an order why we're giving someone market-based rates. Is it confidential only until we have to use the information to justify the result?

MR. WROBLEWSKI: If you come up with a test that says, based on the confidential data, that if you look at the amount of hours in which prices could be increased and you come up with kind of an average look that says they have failed the test without looking at the actual sales?

I mean, the confidential data that I was imagining were sales data, transaction data, was service denied or was it allowed in, those types of things, which are the component pieces in your determination. Based all on that after the fact wouldn't be confidential.

At the Commission, whenever we grant a merger -- or approve a merger, I should say, we collect all the confidential data and we make it -- either we go to court, where we say it's okay and we put out a Public Interest Statement indicating what the problems are or what problems there weren't, as the case may be -- so I think you can kind of get around that problem by making a determination that takes into account the confidential data but not necessarily reveals it in your decision.

MR. LARCAMP: With respect to the sales information, we require that to be reported quarterly. With respect to the denial of service request, that really is concerning transmission providers, which are standards of conduct required to be separate from any affiliate generation. So I guess I'm sort of scratching my head about what data would be confidential that would be available to someone requesting generation market-based rates.

MR. WROBLEWSKI: I'd imagine that some suppliers in the market would say that they couldn't provide information that would be confidential. I was just trying to give you a way to do it. If you're saying there is no confidential data, then that's fine, please don't take into account my remark. I was trying to say that if, in order to make a more fulsome decision, you need to get confidential data that otherwise wouldn't be available, then you should get it. That's all I was trying to say.

MR. RODGERS: I had a question about whether -- we've been kicking around pivotal supplier screens and market share screens. I'd be interested to hear if you have a perspective on a completely different type of screen that you could recommend that might be helpful for analyzing these energy markets.

MR. WROBLEWSKI: You know, I don't. The screens in and of themselves, if you define the markets properly and you do them over a representative sample of hours rather than maybe just peak -- that has some problems -- and then you try to do an accurate calculation of who was in the market based upon what the prices are, that will probably give you a pretty good indication.

But I think if you do it on total capacity, either uncommitted or not committed or installed or whatever, but you're not looking at what the prices are, this whole discussion we've had about eight, ten, and six and seven -- I kept thinking well it doesn't really make any sense if you don't know what the prices are for whether part of that 8,000 is going to be deployed. Obviously, it doesn't make any economic sense to deploy generation that has a cost profile higher than the price you're going to get in the market. That's what I'm saying.

MR. PERLMAN: Just a little follow-up on that. When I understood you to talk about saying run the various screens, I was also thinking when you were talking about this one hour only shows the one peak hour only one time a year, that you're really recommending -- or at least I'm asking, are you recommending that we require some level of sensitivities for here's this one screen process giving us five scenarios so that we have sensitivities for that peak hour for the average --

MR. WROBLEWSKI: That would certainly be one way to do it. Obviously you don't want to burden people who do not have market power with certain types of regulatory requirements and data requirements. That doesn't make sense. But if you're looking at the different angles and somebody fails, then requiring some type of sensitivity going forward, that makes more sense. Obviously you know ahead of time -- your applications are every three years so you know who is coming up -- and I would assume you would know who is coming up -- you can do your own type of analysis ahead of time to say if you have a smaller window of time in which to make these determinations, you know, that can be accounted for.

MR. O'NEILL: We've heard from certain analysts that we shouldn't be concerned with collusion, either explicit collusion or implicit collusion, because the anti-trust authorities will take care of it, so it shouldn't be our business. How do you feel about that?

MR. WROBLEWSKI: What the anti-trust laws get at are agreements. If there is an agreement between two competitors to price at a particular point or reduce output in certain conditions, obviously the anti-trust laws can go after that. If, on the other hand, after consecutive bidding into markets you realize -- I'm saying "you" as a supplier -- a supplier recognizes that if it does certain things other people will do certain things and it's tacit collusion and actually it's in their best interest to do that, anti-trust laws can't get at that. It's not an explicit agreement. It's not an agreement unless there is some type of way to find there is an agreement.

And one of the ways you can look to see if there is an agreement is to see if there is some type of punishment for someone who is deviating from that particular behavior. If there is no type of agreement there, you can't really get at it. I think if you look at the merger guidelines we always talk about it in terms of facilitating coordinated interaction. We try not to allow mergers that would facilitate coordinated interaction after the merger is over. So we're always aware of that possibility. It's rational market behavior: see what your competitors are doing and then find out what makes sense for you.

So to answer your question, if there is an explicit agreement, yes, the anti-trust laws can be used. If there is tacit agreement or tacit collusion, in which there isn't an agreement per se, it's more problematic. So you should be worried about that.

MR. O'NEILL: So the pivotal supplier test checks the unilateral, which is probably the most extreme form of market power, but doesn't check the tacit collusion or the behavior we should be looking at?

MR. WROBLEWSKI: That's correct.

MR. BARDEE: Are you suggesting we use market share analysis to look for a risk of collusion?

MR. WROBLEWSKI: I think a market share analysis can give you a window into seeing whether it's possible.

MR. BARDEE: We've used one in the past as part of the hub and spoke. We used it only to look at unilateral risk of exercise of market power.

If we were to use a market share analysis prospectively to look for a risk of collusion, would your idea be that we convert it into HHIs and use the kind of scale that the DOJ/FTC guidelines provide?

MR. WROBLEWSKI: You certainly could. Obviously you wouldn't use the merger or the 1000/1800 numbers there. DOJ, when it deregulated oil pipelines -- you know the report -- when DOJ did a report on deregulating oil pipelines, they talked about what concentration level, if you're coming down, and I think the number was like 2200 or 2300. That sticks in my mind. It was higher than the 1800 number. That seemed as though it were a sound rationale. I'm sure you have the report somewhere in your files.

It would be a different scale but, yes, HHIs would be appropriate. Remember, at that point, you're only looking to HHIs for one hour. You've got to make sure they're kind of being weighed to see what the actual behavior would be.

MR. BARDEE: If we applied analysis like that and found excessive concentration, right now we've been using -- only in the context of an applicant comes in and seeks market-based rates. Coming up with a remedy that says you, the applicant, can't have market-based rates because there's a risk of collusion between you and three other people ignores what we should be doing about the three other people. What's your thought on that?

MR. WROBLEWSKI: Say that again, so the other three do not have market power -- if the other three do not have market-based rates? If the other three do not have market-based rates -- I'm not sure if all four of them do if you had a market that they had equal-sized competitors.

25% -- I'm doing the math in my head, and that comes up with like a 2500 HHI. Is that right? That would be a closer call. You'd want to look at other things: you'd want to look at entry impediments, you'd want to look to see are they operating, how is their transmission being dispatched? There would be other things you'd want to look at: what the demand responsiveness is in the market. There are other attributes you'd want to look at other than just focusing on solely whether they were 24.99, they're okay, 25.01, they're bad.

MR. O'NEILL: You said the magic word, "demand responsiveness." These markets have virtually no demand responsiveness to speak of, at least the short-term markets. How should that figure into our calculations?

MR. WROBLEWSKI: Once again, it should be recognized that there is no demand responsiveness. I realize it's not FERCs ability to require it, but I think if you're trying to assess whether customers are going to be paying higher prices, the fact that they cannot switch to a new supplier doesn't really help the applicant because of the lack of demand responsiveness.

MR. RODGERS: Why don't we move on to our next panelist?

Thank you very much, Mike, for your helpful comments. I know that will greatly inform our decision making process.

Our next panelist was supposed to be Bob Stibolt with Tractebel Corporation. However, Bob was taken with the flu yesterday, so he was unable to make it. In his place, Tractebel has asked Mark Haskell to come and give comments. Mark is with Brunenkant and Haskell, LLC. Joining him at the table to help answer questions in the Q and A is Lily Teng, the Vice President and General Counsel of Tractebel Energy Marketing.

Welcome.

MR. HASKELL: Thank you. I will be pinch-hitting for Bob Stibolt and I'd like to present Tractebel's views on the issues that have been set for this particular panel. I would note that Tractebel has submitted written preconference comments which have been made available on the remaining issues to be discussed over the next two days.

Tractebel is a subsidiary of Tractebel North America, which owns, operates and develops natural gas projects and electric generating units throughout the United States. Neither Tractebel nor any of its affiliates own or control electric distribution or transmission facilities in the United States.

Tractebel supports the continued development and expansion of fair and open electric markets in which both transmission market power and generation market power have been adequately and effectively mitigated. Participation by any seller in a market that is administered by a functional independent system operator or an RTO which has in place Commission-approved market monitoring and oversight programs is the most effective way to demonstrate the mitigation of market power. Therefore, Tractebel supports continuation of the exemption for sellers who participate in ISO and RTO markets from the SMA test.

As the discussion today indicates, no single market power screen ever will be exempt from criticism. Tractebel supports the Commission's pivotal supplier screening analysis with one substantive proposed modification.

We propose that newly-constructed generation by new market entrants, as well as capacity additions by existing generators with non-dominant market shares, should be permitted to occur at market-based rates. In applying a pivotal screen analysis, we believe that the Commission's current focus on installed capacity is proper and should be continued.

Many have advocated in this proceeding today that the Commission should adopt a screen based only on uncommitted capacity, which they define to exclude native load. Tractebel does not agree with this view. Even under the Commission's traditional hub and spoke analysis, the Commission examined both installed capacity and uncommitted capacity. Prior to adopting the SMA screen, the Commission found that at least in markets transitioning to retail competition, consideration of the installed capacity measure was a more relevant indicator regarding potential generation dominance.

More fundamentally, as prior panelists have indicated, ignoring installed capacity and excluding native load is impractical. Many utilities today serve existing retail and wholesale loads through a single portfolio generation. The use of that portfolio can change on a daily or hourly basis. Native load obligations could be met from a wide range of alternatives, not necessarily limited to on-system generation. Parceling out such a dynamic portfolio into retail and wholesale components would be difficult at best and, in our view, would tend to produce artificial and misleading results.

Finally, as noted in its written comments, Tractebel is somewhat concerned that the proposals in the revised portfolio screens proposed by the Commission, providing only for seasonal mitigation through the modified pivotal supplier test, may not be effective in influencing the forward market prices in a manner consistent with the Commission's original stated intent in adopting the initial SMA screen.

Tractebel appreciates the opportunity to participate in this proceeding today and we'll be glad to answer any questions you might have.

MR. RODGERS: Thank you.

Questions?

(No response.)

MR. RODGERS: If I understand you correctly, you support the pivotal supplier screen with two exceptions. What were those exceptions again?

MR. HASKELL: There were two. The first is, as indicated, participants in Commission-approved ISO and RTO markets shouldn't be subject to the SMA screen.

The second point I made was the Commission should recognize and provide an incentive for new market entrants bringing new generation into control areas to provide that generation and market-based rates. Similarly, even existing generation, for example, repowering projects in a control area, should be eligible to receive market-based rates, at least where the existing generator has a non-dominant market share.

MR. RODGERS: Would that be determined on a control area basis? Some panelists earlier have said that the Commission needs to think of markets broader than just control areas.

MR. HASKELL: We haven't work through all of the nuances of our position, but as a threshold matter doing the analysis on a control area basis would make no sense. Again, keeping in mind that what we're trying to develop here is a screen.

MR. PEDERSON: Just a quick clarifying question: when you say new generation being built should be exempt essentially from the screen, if that new generation is being built by the applicant in a control area where the applicant already owns generation, how would you propose to deal with that situation?

MR. HASKELL: That's why we provided the caveat that even for existing generators you have to make a demonstration that you had a non-dominant market position.

MR. PEDERSON: But at some point that market position may change as you add the generation. Shouldn't there at some point be a re-up where we would look at the position in total again?

MR. HASKELL: I think that's a fair point.

MR. RODGERS: Some of the earlier panelists have proposed that the Commission should not attribute to applicants native load generation. If I'm understanding you correctly, you completely disagree with that and think that it should be counted in an installed-capacity type of markets test measure, is that right?

MR. HASKELL: That's correct.

MR. RODGERS: Should any recognition be given for the fact that that generating capacity at times of the year is used to serve native load?

MR. HASKELL: In terms of the Commission's need to develop a screen to evaluate market power for purposes of testing for generation market power, we think it would be extraordinarily difficult for the Commission to effectively segregate wholesale and retail operations. For example, if you had a utility which functioned in two or more states --

one state has retail access; one state doesn't -- how do you parcel it? Only the utilities generation between the wholesale and retail function, but within the retail functions, between the retail jurisdictions with retail access and without, how do you account for the fact that portfolio-based dispatch is very dynamic? There is not a static obligation or static requirement that particular units be dedicated over the life of the unit to serve only retail obligations. Theoretically it could be done, but not in the context of developing a screen for market-based power -- for generation dominance, rather.

MR. O'NEILL: Let me ask you a question, going back to Steve's example. I believe he said Entergy was a net buyer on peak. It's net because its load exceeds its generation capabilities. Shouldn't we, at that time, be worried more about Entergy as a monopsonist rather than an entity that wants to see high prices? Shouldn't we look at them as an entity that wants to see low prices?

MR. HASKELL: I think that the Commission's ability to pursue allegations of monopsony power is somewhat limited.

MR. O'NEILL: You mean that you're not entitled to earn a return on your investment, so if Entergy basically decides to not give you access to the market and negotiate a very low price, that that wouldn't be something the

Commission should go after?

MR. HASKELL: Different issue entirely. If Entergy does deny access -- if Entergy were to deny access to competing suppliers, that would be a violation of the Commission's currently effective regulations, and that is something the Commission should pursue more broadly.

MR. O'NEILL: But in that case, the reason we're pursuing it is because we've netted out their contractual position and their obligation to serve native load. Otherwise, we'd be looking at them as an entity who wanted to raise the price of power when, in fact, we should be looking at them as an entity who wants to lower the price of power, since they're a net buyer. But if we use your screen, we would be looking at them to raise the price so we wouldn't even think about them lowering the price.

MR. HASKELL: The incentives that any utility has -- putting Entergy to one side for a moment, which functions in more than one jurisdiction, I think as some of the prior questions indicated directed toward the southern panelists -- can change. A utility may have an incentive to increase prices in a jurisdiction where it has a sharing mechanism for wholesale sales. It would be very difficult for us to generalize on that basis.

More fundamentally, where we come down to is there is no theoretically pure test. We recognize that. We just see such substantial difficulties in meaningfully segregating native load from an overall generation portfolio that we think the Commission's current focus on installed capacity is sound.

MR. BARDEE: Let me just ask you to clarify your answer there just a minute ago. Are you saying that even a net buyer, if it can pass through the higher costs onto its ratepayers but receives some part of the higher revenues for shareholders in some way because of the regulatory structure might have an incentive to push prices up?

MR. HASKELL: Yes.

MR. BARDEE: Thanks.

MR. PERLMAN: A couple of questions in sort of a clarifying mode. Are you saying because of the difficulty of taking into account the generation portfolio and matching it up with the retail obligation that the retail obligation should be completely disregarded in determining whether there is some sort of market power issue and market-based rates granted?

MR. HASKELL: For purposes of the initial screen analysis. We're talking about screening here. We believe that segregating native load isn't a meaningful exercise for the Commission to pursue.

MR. PERLMAN: Are you saying that if you would then fail the screen potentially you would then take some further step? What would happen there?

MR. HASKELL: As later panels will address, the Commission has two options. Either the failure of the screen would trigger predetermined mitigation methodologies or, as some have suggested, that would simply be one data point. The Commission would undertake a more intensive examination of whether there are additional factors that indicate that there was no incentive to exercise market power.

MR. PERLMAN: You also said something about the monthly mitigation impacting forward prices or price signals. Could you elaborate on that, please?

MR. HASKELL: One of the concerns we had with the Staff people -- and it may, quite candidly, be a lack of understanding on our part -- is that when the Commission fashioned the original SMA test it was proposing, through mitigation measures other than under consideration, effectively to create a standard offer of service which in its view would have the effect of mitigating not only short-term markets but also forward market prices.

What we see in the Staff paper is a suggestion that there would be monthly or even quarterly mitigation methodologies, as the Staff has outlined. And we question at this point whether that would have the same impact on forward market prices as the sort of year-round mitigation that the Commission was originally considering in the SMA order. That's the basis for the concern.

MR. HUNGER: There's an analytical problem with the positions. On the one hand, you say you support some sort of pivotal supplier concept, some modified pivotal supplier. On the other hand, you're against netting out native load obligations. If you do that -- if you don't net out those native load obligations for any utility with a large native load obligation, it will always be pivotal, almost always be pivotal at some time during the year.

Basically -- I realize it's analytically tricky to try to figure out in a portfolio how you separate them, but if you don't then the test or the screen really devolves into a question of do you have a large native load obligation or not? And, if you do, you fail. And if you don't, you have a chance at passing.

That's one of the problems with the existing -- one of the reasons why we're taking a closer look at the existing SMA. Utilities just weren't built -- it was never set up so that a company's generation -- you'd always be able to bring in enough generation from outside to serve everything, including the native load.

MR. HASKELL: Fair point. The Commission has been struggling with this point for a very long time, as Dr. Henderson indicated. Even in connection with the hub and spoke test, the Commission recognized back in 1993 that even if you were to exclude some portion of native load, you can't exclude all of it. Once you cross that threshold for screening purposes, what do you exclude, how do you allocate it for purposes of developing a screen for initial analysis. Yes, it's difficult. Yes, it's a rough cut. But the notion of simply ignoring installed capacity and excluding all native load we think is unrealistic.

MR. HUNGER: If the screen is not based on operating costs of the plant -- not like a delivered-price test or something, if it's just do you have enough capacity, in a sense, it really doesn't matter what portion of the supply you chop off. If -- in Steve's example, if you had 8,000 megawatts of native load and 10,000 megawatts of generation for the purpose of the screen to just ask whether or not you're pivotal, it doesn't matter what 2,000 megawatts are remaining.

If you did a test more like what Michael described, where prices did matter, which is the way we do it in merger review, then it's very tricky. Then there's a problem. But for the initial screen, it seems like if you're going to go pivotal supplier then you have to chop off native load obligation, and you can without losing anything for that screen. It may not be the perfect screen, but that would be consistent.

MR. RODGERS: Why don't we move on to our next panelist? Thank you very much, Mark, for your comments.

Our next panelist up today is Gary Ackerman, Executive Director of the Western Power Trading Forum.

MR. ACKERMAN: Thank you, Steve, and thank you members of the Staff and Commissioners for inviting me here today.

Many of the comments I've heard on this panel have been quite excellent, as well as the panel this morning and I think have highlighted important points that I might end up repeating or reiterating here. I've learned a lot, not only from the questions answered, but from some of the questions dodged as well.

What I want to talk about today is our general view of assessing market power and an appropriate screen and what to do when it's present. Because essentially what you have -- and I think most people here would agree -- is an exercise of rough justice. And some of the examples that were provided here by my fellow panelists have suggested in addition to just one measure there might be multiple measures, in addition to the fact that failing one or more measures might lead to certain actions. Those actions shouldn't be automatic triggers of price mitigation necessarily.

It just seems to me, as I'm listening here to some of the comments that have been made, that FERC would look stronger when we have multiple measures and gradual approaches to resolving those problems, as opposed to saying Here's the measure, it's right, right as rain, when we know it's not. Here's what we're going to do about it; Click. Because that set up makes people very nervous that things aren't going to work right.

I guess I come from the environment in the western states where people have been caught in traps that they felt they couldn't get out of -- not easily. Let's try and go back to the simple approach, if we can, and recognize that you're not going to get it perfectly right. But keep in mind, too, that simplicity itself is not your goal, because I've seen in these discussions people aim at the wrong target with simple ideas, therefore, leading to massive distortions for either sellers or consumers in the market.

We don't think finding the answers to an appropriate screen are easy to come by. I don't think I'll have to convince you of that and I haven't heard anything today that would push me off that point of view. Quite simply, it's difficult to find an easily implementable method that protects consumers and provides comfort to sellers that they won't get trapped in a system of unreasonable price mitigation.

With the rest of my time today, I want to cover five points that were raised by the Staff's paper, hoping that our comments on each of these five will add to the discussion that's been laid out here today.

On the first issue of whether sellers should be exempt that are selling to an ISO or to an existing RTO, we strongly believe so for the following reasons:

Certainly in the California ISO there's extensive market monitoring and similar monitoring exists at other RTOs around the country. Some of these methods are automatic, as the AAP/AMP would suggest when prices rise too quickly.

In addition, the California ISO has a market monitoring group and, just like other groups at similar RTOs, it's always on the watch for anomalous market behavior and they're empowered to seek mitigation measures using formal means. I would say without too much doubt that my members might believe that the California ISO market monitoring staff sees market power everywhere, even when we don't. But the point is, we don't need another layer of regulation that would be developed here. In the California ISO -- and I doubt that it would make a lot of sense for the other RTOs in the country to do that. I think it's sufficient in terms of what we have for those that exist. Let's not add an additional regulatory burden on sellers.

The second point: with regard to the Staff assumption that mitigating spot prices would be an appropriate incentive for sellers to be more competitive in offering long-term contracts, thereby avoiding the spot price mitigation, we strongly disagree. This is a dangerous assumption and let me tell you why.

We have witnessed in all too many sad examples where there's a perceived incentive on the part of the seller, which becomes a negative incentive for the buyer. That is to say you've set up a situation where yes, it's true that if I were a seller, everything else being the same, I would want to avoid spot price mitigation and enter into long-term contracts.

But you've got to remember the buyers look at that. They're rational buyers, being mainly utilities in the State of California, with the exception of the 5,000 to 4,000 megawatts of capacity that goes to the direct access customers. They look at it completely differently. They're saying why should I enter into a bilateral agreement when I can, for free, get the protection of spot price mitigation which you're offering me.

That is what I call a perverse incentive. You have sellers going in one direction; buyers going in another direction. As a result, nobody meets. It's not theoretical. We observed this kind of behavior early on in the ISO, and you all know this. When utilities in the state feverishly underschedule load in the day-ahead market in order to protect their customers and, therefore, rely upon the California ISOs real time price cap -- and a price cap is simply another form of mitigation. That perversity was one of the major reasons that the original market in California failed, not the only, but certainly an important reason, especially during that supply shortage period of 2000 and 2001.

There is another example. As a result of trying to clean up the mess in California during that time period, today market sellers in California are under a must-offer obligation to the California ISO. The buyers, that is the utilities again, know very well that by having this must-offer obligation it provides additional real time capacity to the market which suppresses ancillary service prices and provides a nice cushion for operating reserves, which is the very reason why the utilities in the State of California have asked for a gradual ramp in the reserve margin between now and 2006, I believe, or 2008. The point being it's well below what we would anticipate a reserve margin target would be for reliability by anybody's standards. They know the 3 megawatts are there, they're available every day through the must-offer obligation.

So again here we have an example where we have perverse incentives that are working in opposite directions. The must-offer obligation as well moves up the retirement date of the older units that are out there. The owners of the unit are looking at that and saying We're not making very much, we're doing some cost recovery on minimum load and then we're not getting compensated for the fact that we're running a minimum and we have all this spin out there and we're not collecting anything for that. And that just says to them Yes, it's time to retire this thing a little bit earlier than we originally thought.

So our caution to the Staff is that incentive sellers behave one way and they may have an equal and opposite reaction by buyers, setting up an intolerable situation. Work with assumptions and guidelines where there are balances of interests between the sellers and buyers so both parties are motivated to transact deals.

There was another feeling expressed by my membership regarding spot price mitigation. It's a little bit more complicated, and it goes something like this: it's one-sided to say if you fail a market test or a market power screen -- keep in mind that there's no capacity requirement on the buyers -- that is to say, the thinking here is that the only cost recovery you're going to be entitled to is your variable cost. Whether that's right or wrong, that's the thinking most people have in this business. If there were capacity markets, that would be great. Then at least the owners would be receiving some revenue for the fact that they have capacity available. In the West, that's relatively more important than in the Midwest or the East or the Southeast or anywhere else because of the larger role that hydro plays. When you have inadequate hydro years, as we discussed earlier today, that's when you have less water, more natural gas production of electricity; a normal hydro year, it balances out differently. During the time when there's abundant hydro, nobody would be receiving any compensation through the energy prices in order to compensate them for the capacity, as well as the energy.

Given that we are talking about applying the screen in areas that do not have existing transmission administrators nor any kind of markets -- so I'm thinking outside of the California ISO -- it's pretty difficult to see how FERC can impose a capacity market requirement on buyers, not that you suggested it, but it would be I think unlikely that you could ever balance out these competing interests. Therefore, it is equally difficult for us to understand how FERC intends to achieve a balanced approach to handling mitigation of market power simply by relying on spot price mitigation.

One thing for sure: an imbalanced approach will appear to favor buyers but ultimately we'll get burned because it will discourage new investment in that area of the country. If it's all down-side risk for the sellers without any commensurate up-side opportunity, there will be no sellers.

Third point: on the matter of residual transmission market power -- and I think we've heard a lot of discussion about this today -- we believe the problem is very real and presents a formidable entry barrier to potential market participants. This is predominantly the case in areas of the country where an RTO or ISO does not yet exist. The lack of non-discriminatory interconnections and new generation sites plagues developers' new projects; we've heard about this.

We believe there are a range of mitigation measures the Commission should pursue, all the way from what I call the soft path of third-party independent administration of OASIS sites, to the harder path of a more formal and absolute separation of generation and transmission functions within a vertically-operated utility. Between that range, there might be many different solutions.

A caution, however, is that at the low end of the mitigation scale -- the soft path, as I called it -- a third party independent administration we don't think will be terribly effective or meaningful. Vertical transmission market power is a structural problem that requires a functional separation of generation from transmission. It would be so much easier to say put them in an RTO and let's move on forward. That option might not be available for a while.

Number four: should market power measurements be applied to an annual peak hour or upon monthly peaks? First, we want to comment that the Staff paper's suggestion that mitigation, if triggered by a single month, would instigate, for example, a three-month period of mitigation, is ill-advised. It might be administratively easier to implement seasonal mitigation, but it seems to us that a seller under that situation would be punished beyond reasonable if the test failed in a single month.

So again market power, in our view, is not a short-term phenomenon, it's not something that occurs and disappears like a skin rash. It's a functional problem. It's existence points to long-term fundamental problems that must be addressed accordingly. So we're not very comfortable thinking about a quick on-and-off mitigation measure. That's the kind of nervousness that gets people to stay away from markets where investment opportunities might be available but they'll say too risky.

Lastly, on the issue of the type of price mitigation -- cost-based versus the single market price, which were two of the options that the Staff paper proposes

-- we weigh in as follows:  cost-based rates are an administrative nightmare and require significant detail; billing determinants that constitute full costs.

Alternatively, it's hard to imagine a single market price in an area that doesn't have an organized market.  I'm thinking now, for example, of the Pacific Northwest.  We could conjure up all kinds of ideas about a single price, but would it really apply in all instances? I'm not too comfortable that it would.

What would be the benchmark price?  We would recommend, rather than a cost-based price or trying to find a single market price, supporting a seller-specified bid cap that is based on some measure of opportunity cost adjusted for risk factors, which were done in the past in California, such as buyer credit, fuel price, swings, transportation for fuel, that is, differences, et cetera.  We didn't have sufficient time in preparation for this conference to come up with a list of mitigation measures or even fleshing out the one I just identified here, but I think we would certainly be in that spirit of a somewhat specific bid cap. However, if Staff is interested, we're more than happy to provide something after this conference in writing for your consideration.

I'll be happy to take your questions.

MR. PERLMAN:  I have a question.  You spoke a lot about mitigation but I may have missed it when you talked about which screen -- or how we might measure to see whether sellers would be eligible for market-based rates outside the ISO market. What is your recommendation to us on that?

MR. ACKERMAN: At the outset, I tried to point out that there's no single screen that makes us feel terribly comfortable. Based on the comments I have heard today, it seems to me -- and I think my members would agree generally -- that having multiple measures might be more comforting than having just any one single measure. We see all the obvious problems with any one single measure. I don't think you're every going to erase any of the problems with one single measure. But we agree that this is an exercise in rough justice; therefore, any measure must be simple, transparent, easy to create or validate independently. That's far more important than picking the right measure.

That's why I said at the outset it's not so important exactly which measure you take. Obviously there's a pecking order, favorable to least favorable, we haven't provided you today what we think is the most favorable and the least favorable. I don't think we feel terrific about any of them. The point is -- and this is where I really appreciated what Michael was saying earlier, maybe you just don't take one measure, maybe the answer is you take several measures, look at several measures and weigh those, then see what your next steps are going to be after you see what the results are.

MR. PERLMAN: Did you have any reaction to Mr. Apperson's suggestion that the West was effectively one single market and that there should be a move towards a west-wide screen as soon as possible in a generic proceeding?

MR. ACKERMAN: I did have a reaction to it: let's clear it up.

(Laughter.)

MR. ACKERMAN: If I agreed with him, it would contradict what I already said. We pointed out that we think there should be an exemption for existing ISOs and RTOs, the California ISO being separate.

I would think it would make more sense to have something that falls into the regional or subregional buckets that we think about RTO formation in the West, which would be the Northwest and the Southwest. That would make, I think, more sense and be consistent with my comments.

MR. O'NEILL: Gary, do you perceive that independent power producers in the West in service territories that are not served by ISOs or RTOs would fail the test?

MR. ACKERMAN: I have no idea whether they would pass or fail the test, so I don't know how to answer that question. Is it possible? Yes, it's possible.

MR. O'NEILL: You were worried a lot about mitigation, that they would first have to fail the test before they would be mitigated.

MR. ACKERMAN: It's an appropriate comment, Dick, that my members are more worried about mitigation than the passing or failing of a test. I can't explain exactly why that might be the case. I can give you all kinds of theoretical reasons, but their experience has been over the last five years that mitigation is fairly ugly and it's something that we've lived with or had hanging over our heads for some time.

MR. O'NEILL: Have they ever failed a test?

MR. ACKERMAN: Not in the West they haven't failed a test. I guess they believe that a reasonable test or multiple tests of reasonable magnitude would provide some sort of guidance. I think they're more focused, more worried about what would you do next? Is it just going to be a snap-on mitigation and snap-off when market power changes?

And another point you made, Dick -- since I hoped you weren't going to ask me the question but since you probably are going to any way -- which is in the West market power is most pernicious when it's a low hydro year. Do we foresee a paradigm where the FERC Staff, every year, has to come in to the Western region and do an evaluation of hydro power circumstances and then decide whether or not it's market power? That's not a paradigm that we feel very comfortable with or makes a lot of sense.

What we would hope for is that you have something straightforward, simple, elegant, and, if it identifies a problem, let's look at some of the steps for mitigating that problem, but not necessarily a snap-on spot price mitigation.

MR. O'NEILL: In the East, two of the ISOs have implemented scarcity pricing that says that when the market becomes scarce and there's no withholding, the price goes up significantly. The new New York market design -- market proposal, the price can get at least to $1,800.

MR. ACKERMAN: That price is a dream in the West.

MR. O'NEILL: That's because it's an ISO and the market is monitored.

MR. ACKERMAN: I think the difference here is that in the East you can have a situation that suddenly sees a price rise and then a decline. You're talking about, you know, hydro availability or the lack thereof. That's not a one-day event. That's not a one-week event, that's not a one-month event. In the last instance where we had this, it was an 18-month event. Do we really want to be in a situation where we're under some sort of price mitigation for 18 months? Well, I don't know.

MR. O'NEILL: You're thinking about a price cap.

MR. ACKERMAN: I don't know if we're thinking about a price cap, but I've given a recommendation about a more specific price cap that might make more sense to us.

MR. O'NEILL: We don't have those in the East.

MR. ACKERMAN: That's right. But I think that would fit the bill.

MR. O'NEILL: In ISO market designs, we don't have seller-specific price caps -- or they're very high.

MR. ACKERMAN: This might have to be a point of departure between eastern ISO and the West.

MR. PEDERSON: With respect to exemptions or sales into RTOs that have Commission-approved market monitoring and mitigation, how would you respond to arguments that the current measures that are in place today are not sufficient to support such an exemption?

MR. ACKERMAN: Outside the ISO or inside?

MR. PEDERSON: Currently they exempt sales into the RTO because it has Commission-approved market monitoring.

How would you respond to the argument that current monitoring and mitigation is not sufficient to support that exemption?

MR. ACKERMAN: I just couldn't agree, based on anything I know about it or I've seen in the last five years based on California. If anything, they're hypersensitive to market power. Anybody -- Seriously, other than for political reasons -- and we do know of people that say things for political reasons who would honestly admit that in the case of the California ISO -- which is the one I obviously know -- that they are serious or have sufficient tools at their disposal to do something about market power. I just couldn't take a comment like that seriously.

MS. LEAHY: Gary, on the issue we talked about a fair amount today in terms of whether native load should be taken into account in determining -- regardless of which screen we use, do you have a position?

MR. ACKERMAN: No, we don't.

MR. PERLMAN: Am I correct that your membership is typically independent power producers and power marketers? Do you have a number of utilities in there as well?

MR. ACKERMAN: We do have utilities in there as well, as well as public power, as well as investor-owned, as well as municipal. When it comes down to setting the policy for a group, that's a group of individuals or companies who, for the most part, are not utilities and are independent power producers or merchant generators. The reflection of the policy might be more skewed toward that, but believe me there's a sensitivity about the entire membership and what it represents as well.

MR. PERLMAN: I'm just curious -- if you're comfortable answering those questions -- is there a concern that, as the SMA was originally proposed by the Commission, that many of your membership might fail that, even as originally proposed?

MR. ACKERMAN: No. Going back to my answer to Dick's question, the focus and people's concerns seem to be almost entirely on the mitigation measures and on the pass/fail. Maybe that's surprising to you, but it's not to me.

MR. PERLMAN: If they passed the SMA, they wouldn't be subject to mitigation.

MR. ACKERMAN: That's true, unless circumstances change. And, if anything, we've seen in the West that circumstances change. So you might pass this time, but what about next time or what if you have a bad hydro year or whatever the case might be? We see a lot of levers in all of the SMA screens that have been proposed and a lot of discussion about how we can react to it. And, quite frankly, we've seen a lot of political pressure put on this Commission by the delegation of the Northwest -- not that they've been terribly effective, but it makes us nervous. Because they can make a situation that might appear at first to be stable unstable. That's very much on our minds.

MR. RODGERS: Thank you very much, Gary, for those comments. I appreciate that.

Our last panelist today is Denise Goulet, Senior Assistant Consumer Advocate for the Pennsylvania Office of the Consumer Advocate.

Welcome.

MS. GOULET: Thank you.

While I represent the Pennsylvania Consumer Advocate Office here today, I did want to note that there are several additional offices that support the comments. One is the Maryland Office of People's Counsel, the Office of People's Counsel for the District of Columbia, and the Ohio Consumers' Council.

The message that I heard today, listening to both the first panel and all the speakers on this panel, is that a simple one-screen approach is likely not going to capture everything that you need to review. Therefore, there are additional factors in addition to one screen that you would have to look at. We're here today to give you two more factors that we think ought to be part of your analysis.

The first of those is that any screen chosen has to include analysis of the type of capacity that the applicant owns. The second point is that the screen must also consider where the applicant's capacity may be controlling the supply curve.

In looking at the screens that the FERC Staff paper puts out there for us to analyze, we believe that the CSI screen, the Capacity Surplus Index screen, best answers the pivotal question, which is whether the applicant's capacity is needed to serve load. The other screens that are out there, the SMA, the limited competing supplier screen, don't directly answer this very critical question. We believe the CSI is a refinement of the SMA. Unlike the SMA, it does take into account some additional factors that are very important, one of which is operating reserves, another of which is planned outages. And it provides you a more accurate analysis of the capacity available to the market.

The one thing that I would like to add that is in our written comments that we submitted to the Commission -- it's not in the overview that we've provided at your seats today -- but with respect to this issue of native load, we believe that excluding native load is not a fine tuning of the process unless additional factors are considered. There has to be a full understanding by the Commission of the applicant's total portfolio and how the utilities operate and dispatch those systems.

You've heard a number of people say this, that they don't set aside capacity to serve their native load, it's supplied from the entire portfolio. The annual peak certainly doesn't tell the whole story since the applicant can use its entire portfolio, including some of the capacity that they would have used to supply native load at peak they can use to serve wholesale markets during off-peak periods. So it's going to be very, very difficult for you to try to carve up and get out what's the right amount to exclude, if you can exclude anything at all.

Another factor that you would need to put in is there ability to do economy purchases. If they're serving native load in a state that is not a retail choice state, they're probably under obligations by their state commission to get the cheapest fuel possible to serve load. That would mean economy purchases. What an economy purchase does, it frees up the capacity they own in the wholesale market. That's another factor that you would have to take a look at.

Finally, for a company like AEP, it's going to be very difficult to get an analysis of what's native load. Other people have said this as well, but the point is that AEP serves a very diverse population. Some of the states that they serve are retail choice; some of them are not. If they exclude their entitled load that they're serving as native load, including load they would serve in a retail choice state, you are not doing any favors to the consumers in the retail choice states by excluding their load from this analysis, since that load can't obviously switch. And that's something you need to consider.

So in the long run, we would encourage you not to categorically exclude all native load. We would urge you to look at CSI. But whatever screen you use, you need to modify it and the modifications we recommend again are that you have to look at the type of capacity that the applicant owns, as well as where that capacity is serving on the supply curve. An applicant could pass all four of your screens and still have the ability to exert market power.

That's because not all the megawatts are homogenous. If the applicant were to own, say, a few baseload units and a few peaking units, or even if an applicant were to own all the peaking units in a particular load pocket, they certainly would have the ability to exert market power even though the total amount of capacity that they own would pass one of your screens. So their market share may be small, but they may own the right kind of unit nevertheless to exert market power. These are the additional issues that we would ask you to factor in to the analysis.

We would also ask you to fully analyze any regularly-occurring load pockets. To simply state that the correct geographic market is a control area, we think will miss a lot of areas where market power is exerted.

Pennsylvania, Maryland, Ohio, District of Columbia are all within RTOs; in particular, most of them are within the PJM RTO. Yet, nonetheless, we have load pockets that occur with regular frequency and market power could certainly be exerted within those load pockets. I'm sure this will happen in non-RTO regions as well.

A number of people have asked you not to apply the screen within an RTO or an ISO region. We would respectfully disagree. Membership in an RTO may mitigate vertical market power, but it certainly does not mitigate horizontal market power. In fact, if you look at the PJM state of the market reports for every year for the past few years, you will note that PJM has always noted the problem in its capacity markets that they are very highly concentrated during peak periods.

This Commission alone has the responsibility to assure that rates are just and reasonable. That responsibility should not be sloughed off to a market monitor by running the screens within an RTO region or selling within an RTO region. If nothing else, you are flagging the potential for the exercise of market power; an area that the market monitors will certainly carefully scrutinize.

We know the existence of market monitors alone is not a guarantee that market power won't be exercised. We've seen that in California; we've seen it in some of PJMs markets as well. Even though there were no rules that were broken within the PJM capacity markets, gaming certainly did occur, prices certainly did rise to unacceptable and non-competitive levels and stayed there for three months, all to the disadvantage of the consumers within the region. So we would encourage you to also take a look at extending the screens to the RTOs and the ISOs.

I'd like to make a final note on the bilateral markets. There's no evidence that the short-term markets are an adequate substitute for long-term markets, and we don't believe the fact that there is a short-term market alone is going to exercise enough discipline on the bilateral markets. This is especially true -- there's certainly a need for long-term contracts, especially even in RTO regions in retail choice states, especially when you have a utility that has firm provider of last resort obligations or supplier of last resort obligations.

Within Pennsylvania, we have several of our utilities that have divested the generation and yet remain saddled with their obligations to serve the load within their region. So they depend extensively on long-term forward contracts. We would encourage you to not exclude bilateral contracts from the running of your screen analysis.

In concluding our remarks, what I'd like to leave you with is the fact that it's too simplistic to think that a single screen is going to capture every possible opportunity for market power or even give you a good handle on whether market power can be exercised or not. We believe you need to consider many factors; I'll list a few:

We think that looking at the pivotal supplier analysis through the CSI screen would be a good start, but that you shouldn't discount looking at market share as well. You should also be looking at the supply mix and the ability of the applicants' units to control the supply curve. You need to be carefully looking not only at control area wide analysis but the load pockets that can occur within those control areas. Finally, we think it's critical that you look at what the incentive of the applicant is to exercise market power. I think looking at where the units control on the supply curve is probably a good start at looking at those incentives. So we would ask you to exercise good judgment by looking at a whole realm of factors, rather than focusing just on a single simplistic screen.

MR. RODGERS: Questions?

(No response.)

MR. RODGERS: Can you tell me about the incidents in which there have been exercises of market power, say, in the PJM markets? How often has that happened?

MS. GOULET: There's been two incidents that I'm aware of. One is the situation that occurred with the capacity markets in the spring of 2001; as I said, there were no rules that were broken. The rules were wrong. The problem was it took 3-4 months before we could fix the rules and get them right and change the incentives to exert market power. As a result of that, prices were significantly higher than competitive markets would have otherwise dictated.

The second was a situation -- I'm trying to think if it was the summer of 2002; I think it may have been the summer of 2002 -- the way there were imports coming in through some of the interfaces. Some of the utilities were bringing in power across the interfaces in to PJM but they were scheduling it in one direction but they were actually bringing in power through a different route. It resulted in some anomalies in the prices at those interfaces that was actually detected very quickly by the market monitor. And it was in that situation -- there was not a rule that needed to be changed, so that situation was able to be corrected with relative ease. The concern we have is that we don't know what all the potentials are for the exercise of market power. We would err on the side of caution.

MR. LARCAMP: Why, if I were an investor, would I ever want to give money to build a new plant if I don't have the certainty of being able to play by the market rules that are in place until they're changed?

We all know the positive incentives for efficiency under cost of service regulation; that's why we started down this path towards competitive markets in, what was it, '85 or '86.

It seems to me we have a fundamental choice at the Commission: we can hold the reins tight and we can go back to cost of service and all have our next version of nuclear cost overruns and we'll probably be in gas-fired generation -- I'm sorry, I've got my cold again there -- because the supply source will become prohibitively expensive. Or we can facilitate a reasonable balancing scheme where investors will be confident that they'll have a reasonable opportunity to recover their costs. That's all we owe any investor, cost of service or competitive.

MR. LARCAMP: I guess I'm concerned about being too quick to define people playing by market rules as something inappropriate. If the rules are bad, we ought to change the rules on a prospective basis.

I think that's a risk that cost of service sellers and market sellers have faced since 1935 with this Commission.

MS. GOULET: We certainly walk a fine line when we're trying to balance those two competing interests. We see the Federal Power Act as charging you with the responsibility to protect consumers against the exercise of market power.

If the rules are wrong, clearly we need to change the rules. But if the system is set up in such a way that it takes time to change those rules, it doesn't mean that it's right to continue to exert market power and charge unjust and unreasonable rates.

MR. LARCAMP: I find it ironic that if the default of cost of service -- and the cost of service is higher than market -- that we protect customers by moving more in the direction of the cost of service.

There are areas in PJM that are load pockets where there has been an inability for the last five or six years to provide sufficient incentive for people to build that generation.

Looking over across Bay Bridge, we know that there's a load pocket there. There needs to be a way to incent additional infrastructure for the long-term solution.

The cost of service hasn't worked in some of those areas. Why would someone on the street part with their valuable money? I agree it's a balance.

MS. GOULET: We didn't recommend cost-of-service based rates in an ISO and our TO region in our comments. We actually recommended the split-the-savings approach there.

I would agree with you that it doesn't make sense to go back to cost-based rates if cost-based rates are actually going to be higher than competitive market rates.

The problem is, what do we do about the load pockets where you do have the ability for people to exert market power? And just exerting prices at a scarcity price doesn't necessarily mean that market power is not being exerted.

It may not be that generation is the right solution for a load pocket. It may be that transmission has to be built into that area.

MR. LARCAMP: Or demand response.

MS. GOULET: Absolutely.

MR. PERLMAN: In your example about the other market power circumstance in PJM, where people were apparently doing some sort of ricochet type transaction, my understanding of those transactions is that you don't need to own generation to do it.

You just need to buy power, schedule it out, and schedule it back in, which to me is a gaming type issue that we might want to address that is different than market power in the context of what we're talking about here in market-based rates for sellers.

Would you agree with me on that point?

MS. GOULET: I do. That was not an example of generation of market power.

MR. PERLMAN: Beyond that do you have any suggestions on how we operationalize your suggestion that we look at the type of generation -- our analysis. What would you ask the applicants to come in with so that we can make sense of it in a timely way?

MS. GOULET: I think, one, you could require in the filing requirements that the applicants submit certain data.

One piece of data they would have to submit to you is the types of units that they own. So they would have to identify the types of units they own.
They would also have to give you the heat rates for those units.

Once you have those two pieces of information, you'd have a pretty good feel for where those units fall on the supply curve.

In an RTO or an ISO region the issue is a lot easier to answer because they have the markets that they are running. They know where these units are falling on the supply curves.

If it's possible to get that same data from control area operators and non-ISO or TO regions, certainly that's something you could ask for.

MR. PERLMAN: We would then make some sort of judgment to say, well, you're all base load. You're not in that area that sets the price. So you're different than the person who is all cycling who is in the area that sets the price and treats them differently because of their interaction with the market, something like that.

MS. GOULET: I think we're not recommending that you use that data and that data alone to make a judgment.

We're suggesting you use that data as one piece of an overall analysis that you're looking at because that data will help give you an answer to the question, is there an incentive to exercise market power?

MS. LEAHY: Denise, we heard you say that with regard to the issue of native load, excluding native load is not an easy thing to do. That annual peak doesn't tell the whole story. It's hard to carve out -- hard to determine what the right amount to carve out is.

I was wondering whether any of the panelists would care to comment on that? Those of you who have argued that you do need to carve it out.

MR. FRAME: I've been sitting here listening to that argument and wondering what the difficulty is with carving it out. And quite frankly I don't think it's a difficult problem at all.

You can start with the measurement at the peak period and do it then. I've heard the comment that, well, that's not going to reflect that some of these resources that might be committed to native load are available at other times.

If you think that's a significant problem, then you can go to the analysis at the other times, but you certainly can make an estimate of the load and subtract that from the resources that are there.

I just don't think it's a problem.

Now, there is a different problem that was suggested. This was with respect to how am I going to determine AEP's load, because we know that in Ohio we've got retail choice and we have to come up with a measure for what AEP is not serving.

I'm not sure that problem is not tractable either. Estimates can be made. There is data that's available. I just -- that is a more difficult situation with respect to the AEP type situation. I don't think I would suggest that you have to toss out that input into the screen simply because of that.

It might arise in a couple of cases here and there. You just have to do a little more work there.

MS. GOULET: I think our point was that it shouldn't be a categorical exclusion, that there are additional factors that you need to look at, including some of the more detailed analyses that he was just speaking of.

MR. HENDERSON: I don't know if you asked me that question also, but I agree with what Rod just said. I don't think that a reason here for using total capacity is that it's difficult to calculate uncommitted capacity.

If we add up all capacity, you subtract load. The load you subtract is the load you think is not at risk for having their prices raised. It's not in the market. And you come up with a measure that in retail storage states, it might be a little bit more difficult, extra effort.

But if I were AEP's expert -- and I'm not; I can't be -- but I'm sure they could give you the information that I could use to make that estimate. That doesn't strike me as difficult.

You could make this calculation in peak and off-peak times. Just calculate out the peak and off-peak load.

David just said in a 203, that kind of analysis, the available economic capacity analysis effectively does that. It subtracts out load.

It may not be the exact measure of load we would want -- and we might have to tune up that -- but we make those. We take the 714 data and add them up and cut them and do all that stuff. We could make those estimates very readily even in a 203 context.

MR. RODGERS: Thank you very much, Denise, for your comments today.

I have a couple of questions myself I was going to ask the folks from Southern Company that I did not get a chance to ask earlier. And I don't know if there are other questions the panelists want to raise as well or staff wants to raise with any of the panelists.

Going back to the Southern Company rehearing request of December 2001 -- just, I'm sure it's probably fresh in your mind just like it was yesterday.

But I had a statement there I wanted to get your thoughts on. I think it's similar to something you may have said earlier here today even.

The finding says that split-the-savings pricing for spot sales will necessarily be lower than the competitive market price or else the sale will not be consummated.

Does reducing the revenues that would otherwise be credited to the retail customers -- if I'm understanding that right, this statement was made expressing concerns and objections to one of the mitigation measures that the FERC set forth in the November 2001 SMA order.

The application of the split-the-savings pricing, which is a form of cost-based pricing -- it sounded to me -- what I was reading here is that it would not be a good idea for the FERC to impose that kind of mitigation, because among other reasons that would harm the retail customers of Southern Company. Is that right?

MR. MARSHALL: I think what you said is right. Remember, when you're doing the split-the-savings, you have to have kind of an incremental cost of production and a decremental cost for the buyer.

If the buyer has all of your cost information in advance -- I'm not sure that I remember all that, but it may have been a part of that. If you have all that out there, then the buyer will make the right decision.

You will minimize that savings to be split. That is what then we think would be detrimental to the revenues from those sales that go back to our operating companies.

MR. RODGERS: That makes sense. What I'm wondering is, if the purchaser in that arrangement has a retail load of its own, let's say it's a coop or a muni, they have a retail load of their own.

At the higher price their having to pay means that their customers would be relatively harmed versus paying the lowest with the savings price. Is that right?

MR. MARSHALL: If you're talking about the higher price being a market price, certainly if you pay a market price and you can get it below market, that would be to your advantage.

It doesn't seem to me that that's fair to all parties. In other words, if I'm going to buy and I'm a frequent buyer, I'm willing to pay the market price.

MR. RODGERS: The only point I was trying to make or maybe understand better is that I recognize certainly that having a relatively higher price that Southern Company can get in a market that it sells at benefits its wholesale customers because that gets credited back to their retail customers.

But if that buyer is a coop or a muni on the other end of that transaction, and they are paying a relatively higher price, then their retail customers are not benefitting from that.

MR. MARSHALL: First, I have discretion about making that purchase, so I would assume they are making the right choice. It's all about Is this a fair price for both parties?

If it's the market-clearing price, then it would seem to me that is a fair price for most parties. And indeed, if that market-clearing price was above those decremental, there are avoided costs and they would not make that purchase. Nor would we.

MR. O'NEILL: I don't believe the issue is a market-clearing price. The market-clearing price can have significant amounts of market power in it and still be a market-clearing price.

MR. MARSHALL: I understand that statement. I was talking about a market-clearing price where there is not a pivotal supplier, that there's competition out there.

MR. O'NEILL: Okay, so if there's competition, the market-clearing price is a good price. I agree with you.

MR. MARSHALL: That's right.

MR. LARCAMP: But if you failed the screen, in our wisdom presumably there is not a competitive market price in that instance. Would it be a fair statement that in that instance, your view of mitigation depends on whether you are a net seller or a net buyer?

MR. LARCAMP: I think so. I mean we can't rely upon a just unreasonable market price for an area that fails a screen by definition.

MR. MARSHALL: I understand.

MR. LARCAMP: And so at that point we're mitigating. And I think it's fair that the net seller wants to get as much revenue and the net buyer wants to pay as little revenue.

MR. MARSHALL: Better for all concerned if this is a competitive market-clearing price.

MR. FRAME: In the absence of being out and being readily able to determine what that competitive market-clearing price is, recognizing that that's a problem, it's not obvious to me that there's necessarily going to "one mitigation fits all" and one fits all situations where the screen has been failed.

One of the things we have suggested is that perhaps those that fail the screen ought to take the burden upon themselves to propose the particular form of mitigation that would meet the fact-specific circumstances where the screen has been failed, recognizing that those fact-specific circumstances cannot by their very nature make it into the summary screen in all cases.

MR. BARDEE: Focusing on Southern, just to be a little more concrete, specific, let's assume that the Commission at the end of some further proceeding ultimately does continue to find that Southern doesn't pass the screen.

What kind of mitigation would Southern propose? What could we do that you would find appropriate and not harmful to your retail customers?

MR. MARSHALL: I think Rod will answer, but there's one thing I think we want to avoid. Let's say that that happens and that there is a knowledge that somebody could be subject to mitigation at cost base or something in the cost-based realm.

If you are a buyer that should get you really excited because you could deliberately go even shorter in terms of your load or generation and buy energy at cost and avoid any capacity costs.

When you bought it, I think you'd have to be careful, then, of any mitigation that doesn't have some capacity side to it. Otherwise it could be gained.

You had had a thought, Rod, about how you might do this?

MR. FRAME: Yes, first of all, the failed screen, the approach we envision, the failed screen -- look at potentially exculpatory evidence and assuming that doesn't do the job, if there has to be some mitigation, it's not apparent to me that a spot energy market solution is going to desirable in all or even many of the types of cases that we're talking about where you may be dealing with a traditional vertically integrated supplier that's going to have most of the generation and most of the load in the control area.

The thought that I had was that you would look to identify the potentially aggrieved customers -- who is it that might be subject to the exercise of market power by this entity that has failed the screen? -- and see what options are available to them.

And if for some reason they haven't been able to plan appropriately because of the market power problem and obtain the resources that they might need, then it might be appropriate to put some blocks of capacity out for them for the loads in the control area that are subject to the potential exercise of market power in the amount that would be necessary to make them not subject to the exercise of market power and try to come up with a market pricing principle, a competitive market pricing principle for that capacity block.

How that might be, I don't know. If you've only thought the first thing that came to my mind is let's have an auction for this and see what people will offer for that, that's clearly not going to work if there's only one potential buyer or two potential buyers.

So that would be nonstarter. But there might be some external indices you could look at in that case. MR. LARCAMP: We tried demonstrating the cost-auction capacity. It was uneconomic.

I think with Mr. Ackerman that the Commission needs to consider the incentives for buyers to behave appropriately. In terms of the mitigation we select any instance.

MR. FRAME: The example Bill pointed out was precisely the same. You don't want to give people inadequate motivation to bring their own necessary capacity to the table. I think that was Gary's point as well.

MR. MARSHALL: To any degree that there is games to be played, that's a bad solution.

MR. O'NEILL: You know we conduct auctions every day in our ISO markets very successfully to mitigate market power.

MR. RODGERS: I had just one other question for the folks from Southern and then I thought we'd try to go to the open mic session.

On pages 1 and 2 of the affidavit that you filed, Mr. Marshall, back again in December '01 -- and I do apologize for digging up stuff that's so old -- but you mentioned there the benefits to retail customers from operating companies as wholesale trading activities from Southern operating companies, wholesale trading activities --

You state that the operating company's retail customers derive a substantial benefit from wholesale opportunity trading activities because those benefits are accredited to retail cost of service.

And one of the ways that it benefits them is through the reduction of production costs to our native load service achieved by making economic purchases.

So what I am wondering is, is it fair to say, then, that when Southern Company is a buyer, that its bust competitive wholesale market benefits Southern Company's native load customers and that therefore such a market is a very good thing?

MR. MARSHALL: Such a market is a very good thing.

MR. RODGERS: If some will say, "Oh, competition is good for Southern Company, native load customers," then presumably more competition would be even better for them. Is that right?

MR. MARSHALL: As long as you have sufficient competition, as long as you get a good market-clearing type price, you're okay.

MR. RODGERS: I think we have much in common in that regard on that issue. So I appreciate your thoughts on that.

MR. FRAME: If I could just interject one thought. It might be that different observers would have different views as to what that robust competitive market meant and what are the characteristics.

We're at the principle, but the facts matter too. MR.

RODGERS: Their point.

MR. O'NEILL: Would you agree that one of the results we want to achieve from robust, competitive markets is to see the most efficient resources dispatched?

MR. FRAME: I think we want to see the most efficient resources dispatched. I think we want to take it over into a planning context to see the right signals for bringing new generation.

MR. O'NEILL: Just in the short run.

MR. FRAME: And retiring generation.

MR. O'NEILL: On a short-run basis we'd like to see the most efficient units dispatched, right?

MR. FRAME: I think on a short-run basis, but I think the efficiency concerns go much beyond that.

MR. O'NEILL: Of course, they do. But as a short-term measure, seeing the efficient set of resources dispatched is a sign of a competitive market. Conversely, if we were to detect the fact that the most efficient set of resources acknowledging transmission constraints weren't dispatched, we would have to question whether or not the market was competitive. Wouldn't you agree?

MR. MARSHALL: You'd need to look at the causes for why -- and there was not an economic dispatch -- and determine whether those were legitimate or not.

MR. O'NEILL: Could you give me some reasons why the most efficient resources wouldn't be dispatched?

MR. MARSHALL: Sure. You have situations where a particular area where a generator resides and it might be a cost. If this was the incremental cost, the efficient cost, it might be up here.

It may be that that generation is in a must run mode and would have to run. So there are some situations where you're out of economic dispatch.

MR. O'NEILL: I understand that. But I would consider that to be an economic dispatch.

MR. MARSHALL: It's the best you can do given what you have.

MR. O'NEILL: But I'm saying if we found generators that were available to be dispatched but weren't being dispatched that were more efficient than the ones that were being dispatched, we would have to question whether or not the market was competitive and whether or not we were achieving the results that we hope a competitive market would achieve.

MR. MARSHALL: I think if you look behind why that is, if they don't have transmission service, that's one thing. If they don't have --

MR. O'NEILL: It's not that they don't have transmission service, it's that there would have to be a physical constraint. If they can get transmission service, they could certainly execute a trade with a less efficient generator to become dispatched -- and the less efficient generator not dispatched. That's always a better result, is it not?

MR. MARSHALL: I'm not sure what you just said.

MR. FRAME: I don't know where the question is right now.

MR. O'NEILL: If in fact there are two generators, one with a very high heat rate and one with a very low heat rate, and they both have essentially the same access to markets and you saw that more expensive generator was dispatched and the one with the more efficient, less expensive cost was not being dispatched, would you question the validity of the competitive market producing the results that you want?

MR. MARSHALL: The answer is find the cause, make sure that it's a creditworthy counterparty -- do all those things that prudent business people would do. If there is a problem once you've looked into all of that, then there are questions to be answered.

MR. RODGERS: Chairman Wood.

CHAIRMAN WOOD: In thinking through all that you all have said on this panel today, I know a lot of the focus has been on the short term -- spot markets. That sort of was the focus of the Commission's efforts today.

Does the same analysis exist for the longer term forward markets for our market power screen? What's the change in shifting from the tools we would use to analyze short-term market power and market power on a long-term contracting basis?

MR. FRAME: From my vantage point I would probably put the question back to you as to what sort of longer term are you thinking of.

I heard an example this morning about a situation where maybe with the 3-year renewal process for the market power screen that there would be comfort for the first year and a half of the process of that 3-year process.

But maybe there might be some market power concern after the first year and a half and somebody wanted to consider a 10-year contract perhaps.

My reaction is the really longer term things you can bring new generation into the market. If I'm a customer and you're trying to hold me up, I do have alternatives when you make the period long enough.

CHAIRMAN WOOD: Somewhat shorter than the period of construction in either generation or transmission.

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MR. FRAME: Then my reaction is that it's probably pretty much the same tools except that you have a little more work to do in terms of getting the numbers right for that extended time period.

And so there's going to be some uncertainty especially when you try to project what new merchant generators might come in at what point in time and what import capability that might be in a particular situation.

It's the same basic thing with tweaks on the data. Any other takers?

CHAIRMAN WOOD: Any other takers?

MR. HENDERSON: I basically agree with that also. What I was thinking to add to Rod's comments, taking out some of the long-term commitments that you know are going to expire during some period like if you're going to make this like three years out or four years out, you have to do it with the test year.

The test year in effect becomes a two-year or four-year out test year and expiring contracts have to be taken into account. If you accepted the approach, then I was advocating and looking at uncommitted capacity, there would be more uncommitted capacity in that market.

Somewhat more. I don't know how much more, but I can imagine that might be on the order of 10 to 30 percent more uncommitted capacity in the longer term view than in a shorter term view.

I also agree with Rod's comment that one of the reasons why I have thoughts that we focused kind of on spot markets is that the longer term market's demand isn't very elastic, but demand is somewhat more elastic in longer term. Customers do have more choices.

So whatever the problem is, it's more likely, I thought, to show up in spot markets.

CHAIRMAN WOOD: I thought so too until I heard the man from North Carolina this morning talking about he can't get one wheel out of his local system, so he's basically stuck with one supplier.

And the natural barriers to entry from new generation -- the self build option -- are very reduced too.

I thought the analysis would show that uncommitted transmission capacity or as available transmission capacity through those flow gates in and out of the CP&L region might in fact give him some options for short term.

But as far as getting firm transmission over any of those flow gates, it was a zero opportunity by 2010 or whatever the year was. So it made me think, gosh, there might actually be some passes in the short-term market that do not exist at all for the long-term market.

I was just troubled by that. I wondered if this bright panel had any thoughts about what to do there.

MR. FRAME: The situation as I heard it -- and I have not studied the situation -- but it struck me that there's going to have to be something built in this area -- whether it's transmission capacity to the outside.

I think the gentleman mentioned that there was some natural gas problems there. It may be the cheapest, most effective option is to build some gas transport capacity. It may be the best option is to build local generation or to contract with someone to do that on your behalf.

As a practical matter these things are likely to cost money. But that's the way it is. Things cost money.

By 2010 I am sure that the load of Carolina Power and Light -- I think that's the company he was talking about -- undoubtedly will have increased quite a bit. And they're not going to have -- at least based on their current stock of assets -- any uncommitted capacity, so they are going to be looking to add capacity and looking for transmission generation or gas. They need resources.

MR. O'NEILL: One of the problems I think we've heard from transmission-dependent entities is that when they request transmission capacity, the initial response is a very high price.

As a matter of fact, we have an instance here where the initial response was $150. And it was litigated here and it turned out that the cost was $14.

We also have experience in the West. I believe the case was called the Four 7s case, where it took only 20 years to negotiate the transmission contract.

MR. ACKERMAN: That was on a short fuse.

MR. O'NEILL: Fast track, yes. So having the ability to request transmission and get it 20 years later or get it for 10 times what it cost may not be the solution.

MR. ACKERMAN: Let me venture out into some hazardous area. When I think about long-run competitive index -- and there's a little bit of discussion about this factor in the short term -- dialogue that we had today, it had to do with buyer market power.

But if you go long run, if you want to think about the most difficult problem at least in the short run and expand it via factor here, then I would say buyer market power is huge in terms of this.

If I look at the competitiveness, let's say, of California and where it's going, my members would tell me it's declining, that the ability for us to build, finance, and find customers for our merchant plant is not happening.

What's going on is self-owned generation. It's not just happening in California. It's happening in Arizona. It's happening in Idaho. It's happening in Utah.

So we're more concerned, I suppose, in the longest term picture of this whole problem of buyer market power. And I guess you have to look at both sides more seriously as opposed to your seller because to what extent do the buyers really -- being limited in scope to individual geographic areas -- control the levers as to who's going to come in and who's going to serve?

Does that make any sense? Okay.

MR. RODGERS: Commissioner Kelliher, did you have a question?

MR. WROBLEWSKI: If your question was, how do you measure long-term -- the supplier market power and long-term product markets, basically what your question is, I think you just have to define what your product is.

If your product market is three-year contracts, you have to look to see what's the geographic area in which they can serve. And you look to see which supplies are in the market.

I think what you're indicating is there's probably only one supplier or maybe none. Then that's your answer. I think if you use the same techniques that you're using here identifying short-term spot market supplier market power, as you can for a long term, it's just defining what your product market is and then who's in that particular market.

COMMISSIONER KELLIHER: I have some questions for Mr. Wroblewski. You mentioned earlier that it's possible that a supplier could have generation market power in one hour or one day of one year.

If market power is the ability to sustain prices above a competitive level for a sustained period of time, what is a sustained period of time?

I understand the FTC sometimes has found that there actually can be a short period of time.

MR. WROBLEWSKI: It's whether you can sustain prices above a competitive level for a sustained period of time and you have to look --

COMMISSIONER KELLIHER: Can that be one hour?

MR. WROBLEWSKI: It depends. I would think you would make a judgment call. It depends on what the magnitude is. If it's only slightly above the competitive level, that doesn't seem to make a lot of sense.

If when you then look at, say, a total cost figure and you realize that it only had a small, little increment because there was really no market power, in the other 23 hours of the day or the other days of the week, et cetera, et cetera, et cetera, it's probably not a problem.

If, however, you see that the prices are above the competitive level for, say, at various times under various demand conditions that frequently reappear, then I would think you'd want to kind of balance that versus the time when it doesn't appear and make a judgment call as to the total costs -- are they just and reasonable?

COMMISSIONER KELLIHER: Do you consider peak markets to be a different market from off-peak periods?

MR. WROBLEWSKI: Sure. It's a different product. You bet.

COMMISSIONER KELLIHER: You said this earlier. Mitigation through the use of multiple screens is nothing to be alarmed by. Should some screens focus on peak markets and some on off-peak periods?

MR. WROBLEWSKI: That would be appropriate. I think somebody asked that question during the Q's and A's. Should we look at various demand conditions? Peak periods, nonpeak periods. To get a fulsome view of whether a particular supplier has market power, yes, that would be the answer.

COMMISSIONER KELLIHER: If using multiple screens it was found someone had market power in peak periods but not in off-peak periods, then mitigation presumably would be limited to the peak periods as well?

MR. WROBLEWSKI: You could do it that way. It seems if you put mitigation in, it wouldn't -- I would say it's a cap of some sort in those periods where they don't have market power. They wouldn't be hitting it otherwise. Isn't that correct?

If they don't have market power in those time periods, then they wouldn't hit whatever the mitigation is.

COMMISSIONER KELLIHER: So there's no harm to imposing mitigation in the off-peak periods then.

MR. WROBLEWSKI: Obviously it all depends on how you design the mitigation. But I would think that if you're saying that only 15 hours a year under peak conditions this particular supplier has market power and under the other hours of the year they don't, if you put in a mitigation that only dealt with those 15 because the prices were at that upper level -- if all the other times the prices are down here, it doesn't really matter that you're mitigating up here.

It's not going to really affect what's down here. Does that make sense?

COMMISSIONER KELLIHER: I think so.

CHAIRMAN WOOD: If your mitigation from this point forward is that you'll do a cost-based rate, in the shoulder periods you would be -- I think you're assuming a market-clearing price type cap like we had in California.

MR. WROBLEWSKI: It all depends on how you design the mitigation.

CHAIRMAN WOOD: I can think in fact of mitigations that would track on through the entire year for people that failed the screen for part of the year. It just depends how the mitigation was crafted.

MR. WROBLEWSKI: Right.

COMMISSIONER KELLIHER: One last question. Do you think that mitigation should be limited to the bilateral markets? Are you confident enough about the RTO and ISO ability to mitigate market power that you think only the bilateral markets should be subject to mitigation?

MR. WROBLEWSKI: When you mean bilateral markets, you mean non-RTO, non-ISO markets?

COMMISSIONER KELLIHER: Yes.

MR. WROBLEWSKI: I have a couple of thoughts kind of regarding that whole kind of subject. Let me just give them to you.

It seems as though if you're trying to assess market power, it would be easier to do it right in a market that has an RTO.

Why? Because you have all of the data. You have all of various conditions. And you can determine whether under various conditions there is market power and is it being exercised or could it be exercised?

On the other hand, in a market that doesn't have an RTO or an improved ISO, that's much, much more difficult to do.

So in terms of should there only be -- if your question is -- or I'll give you an answer and hopefully this is the question that you were asking. If there was, I think it's important to keep monitoring market power regardless of which markets you're in -- whether it's bilateral or whether it's an RTO or ISO approved.

It's harder to do it in a bilateral market than the RTL because of the data. I'm not sure if that's answering your question.

COMMISSIONER KELLIHER: What if a seller in an RTO region, an ISO region applied for market-based rate authority but their ISO or RTO is part of a broader market, not all of which is in an ISO or an RTO?

The applicant won't necessarily only sell inside the ISO or the RTO. When should the Commission review their application to sell at market-based rates under the same test as a seller in a bilateral market that would be selling perhaps only into a bilateral market?

MR. WROBLEWSKI: I think it requires an overview of whether that particular applicant has market power, yes.

COMMISSIONER KELLIHER: So you then don't think that there should just be a blanket exemption.

MR. WROBLEWSKI: It all depends. Either you do it beforehand and you don't grant market-based rates or you do it kind of after the fact in terms of an ISO and RTO by having market mitigation measures.

It seems if you have dynamic mitigation in which the test is appropriately designed in terms of, say, you're using a pivotal supplier. You're defining the geographic markets properly. And you're including the right customers in the mix.

Then it seems to me you can do it one of two ways. That seems an appropriate way to make sure that that market power is not being exercised.

COMMISSIONER KELLIHER: Thank you.

MR. LARCAMP: Is it true if I'm looking at a five-year product five years from now, what's the role? The longer out we get -- with entry being a discipline for the exercise of market power.

MR. WROBLEWSKI: You'd look to see if you were trying.

MR. LARCAMP: Assuming we have interconnection procedures in place and natural gas pipeline capacity in place or available for building under our certificate policy statement -- assuming all of those -- and I think we can assume the gas stuff because it's been in effect and has been working.

But assuming that, if we're looking at longer term products farther out, isn't our relying on entry as a discipline a legitimate exercise? We don't need the capacity for something that's going to be sold in five years, do we?

MR. WROBLEWSKI: I think looking at five years is awfully difficult just from the way the antitrust authorities do it. We really only look at a two-year timeframe.

Projecting beyond that is awfully, awfully difficult. So when we look at, say, a merger, we look to see if entry is timely, likely, and sufficient. Timely means two years.

In terms of five years I just think that would be awfully difficult to rely on, to make an assumption that your interconnection policies and whatever are going to allow for that problem to be corrected five year from now. I think that's hard.

MR. LARCAMP: Don't many buyers contract more in advance of two years from the expiration of the contract? We know that today -- and we've got a guy in a cooperative in North Carolina that's looking to replace capacity that expires in 2009 and they are looking right now about what are the alternatives to replacing that capacity.

MR. WROBLEWSKI: What is your question then?

MR. LARCAMP: The question I think Chairman Wood was asking is you're moving into a long-return product. Isn't it acceptable for us to rely more upon entry as an acceptable discipline to insure that a reasonable price will be forthcoming?

That's not to suggest -- you know, I mean, if you're looking at a short-term product mix month, next year entry is less likely. But if someone comes in and says, "I want to sell a product," which is five-year power five years out, if seems to me that the analysis takes entry into account differently.

MR. WROBLEWSKI: I don't disagree with what you're saying. I still think if people who have load want to contract for power beginning in 2009, obviously if people are willing to offer that, they can. But to have that discipline your market, I think, is just a little bit more of a reach.

MR. LARCAMP: I guess my experience is that Wall Street's not financing unless you have a firm purpose contract. And your entry period's longer than two years, so the marketplace, I think, is working with commercial relationships that are longer than two years to get new plants financed.

MR. O'NEILL: My understanding of Jesse's point this morning is that it wasn't the availability of alternative generators or suppliers, but his potential and ability to get transmission to get to them.

MR. LARCAMP: And I'm sure if that is that isn't an ability to get transmission at the price to build new transmission or whether or not it was the inability to get that transmission built at a price that was attractive. We didn't explore that because it wasn't his company.

MR. RODGERS: Commissioner Kelly, did you have a question?

COMMISSIONER KELLY: I do. Mr. Wroblewski, you've heard people today talk about whether or not the screen should take retail load obligations into account. Do you have a position on that?

MR. WROBLEWSKI: In some ways I think as long as you recognize what the problems are, taking it into account or not into account, I think you should take it into account and you should not take it into account and look at both, then recognize what it's not telling you in that if you take native load out of the calculation, there's still what I think Dick mentioned earlier. You've got to make sure you're accounting who the potential supplier is in that market accurately.

I think that's probably -- if I had to make a judgment as to what was more important to taking native load and putting it in or out of the calculation or making sure you define the geographic market properly and counting who the suppliers were, I'd put it on counting who the suppliers were and whether they were actually going to offer services rather than to include native load or not native load.

COMMISSIONER KELLY: Do I hear you say that another way to resolve that is to have multiple screens? One that does and doesn't take it into account?

MR. WROBLEWSKI: Yes. What it does is give you a different -- another angle to look at whether this applicant has market power. If they were to fail, one set of screens and pass another, you'd look to see why are they failing that one set of screens -- does that make sense? -- and then see is that a real problem. And you would allow them -- I would allow them -- if I were FERC, I would allow them to come on in and show you more information to show why they don't have market power.

COMMISSIONER KELLY: Thank you. And you also talked about taking price into account in the screen. Is it more important to you to take price into account in the screen or in the mitigation measure.

MR. WROBLEWSKI: That's kind of two questions. In my mind that's kind of mixing up things. Obviously if you're trying to assess whether an applicant has market power, you want to actually see whether they're in the market or not.

Obviously they are not going to be if you start with a premise that each hour is a different geographic market and a different market. And that's basic if hour is a different market and you have a different set of suppliers in every market because if the demand if very low, the price obviously is not going to be very high.

The high costs suppliers aren't going to come into that particular market. You can't really count them in.

If you look at that, that's what I was trying to get at. Obviously we didn't prepare what the appropriate mitigation would be, which is the next step. We haven't really given comments. And we can certainly provide those comments. But I don't have them right now.

COMMISSIONER KELLY: Thank you.

MR. ACKERMAN: Could I revisit Dan's example just briefly here? Is that all right?

MR. RODGERS: Briefly.

MR. ACKERMAN: I want to describe the nightmare my members have. Then it will explain where I was coming from when I said the long-run measure is buyer market power. This is the way they see the world shaping up right now.

A utility, for example, a potential buyer, identifies a need. You said 2009. Let's stick with that example.

So you're in 2003. They say we know that party is going to look for more supply. Therefore we're going to do some site selection. We're going to approach them and see if they're interested in entering into a long-term PPA actually five or six years down the road.

That's not going to happen. Let's move the clock forward. It's 2006. We had a site selected. We have permits. "Are you ready to enter a PPA?" "No, we really don't want to buy from you guys."

All right, we're going to turn some dirt here. Maybe you'll come to your senses. And they start turning dirt, laying the ground level and maybe 50 percent of the construction is completed.

And they say, "Look, we really can't finance the balance of the construction on this thing until you agree to and so --

MR. O'NEILL: Is California another country?

(Laughter.)

MR. ACKERMAN: Yes, for the purpose of this conversation, yes. That's the nightmare that the members have -- is that that's the exercise of buyer market power in the long-run measure of competitiveness.

So I'm glad you share the dream and the nightmare that my members have on that one.

MR. RODGERS: I had a gentleman from the New York ISO who had approached me during the break and also called me yesterday to want to make a comment from the floor. Is he still in the room? Please come forward?

MR. SCHNELL: My name is Alex Schnell, representing the New York independent system operator. I had been prepared to just give a quick prepared statement, but we actually got into some of the ISO issues. I guess I have a couple things that I'd like to say.

I think that some of the confusion that may have come up in the discussion of the ISO markets and RTO markets in general was a failure for a couple of minutes here during the conversation to realize that the ISO's already have their own market-monitoring plans in place.

And those market-monitoring plans are carefully crafted to address the specific markets that the ISO's administer. For instance, the ISO has in place market-monitoring that does look on an hour-by-hour basis at what is happening in its market -- something I believe the staff paper recognizes that the staff proposal would not be capable of doing.

The New York ISO in particular has automated mitigation procedures that can also mitigate on an hour-by-hour basis -- something that the proposals that we are considering today would not be capable of doing.

So I guess the NYISO's concern is that layering these other mitigation measures on top of the NYISO's mitigation measures could result in a number of problems.

First of all, the new measures could determine that mitigation is appropriate when the NYISO measures think that they're not appropriate or determine that they are not appropriate.

Since our mitigation measures are more carefully crafted and are more specifically designed to address our markets, we think that's a decision that really should be made.

Well, the determination should be made by the ISO crafted mitigation measures rather than the more general measures being proposed here.

We see that potentially happening in two ways. Like I said, it could happen where the mitigation measures proposed in the staff paper would apply and the NYISO measures would not.

The alternative could also happen. There could be hours when our amp would trigger a seasonal measure, yet a seasonal measure would not apply because for the entire season there might not be market power.

The NYISO's basic position is that the ISO's specific crafted measures should apply and continue to apply and there should not be Commission measures imposed on top of those already existing measures.

The second concern the NYISO raises in its comments is really an implementation issue. NYISO is concerned that in markets that operate based on market-clearing prices, forbidding certain market participants from receiving the market-clearing price would create large problems with our ability to settle our markets.

For instance, if you were to say that market participant A may only receive a price of $25 based on their cost, they would be the only market participants in the market that we would have to deal with that way.

We would have to come up with special procedures to make sure that when our markets cleared, the dollars were actually taken away. The dollars based on our market-clearing price were taken away from the entity that was limited to $25.

Then we would have to come up with some means of redistributing those dollars to other market participants.

It's in our view -- if mitigation is going to be imposed based on a generic test that applies to all markets, the mitigation at least in the ISO should be limited to the bid.

If it is found to be necessary, it should not apply to deny market participants the ability to receive a market-clearing price that should be based on market forces not on their bid.

Can I answer any questions?

MR. LARCAMP: Aren't we talking about different products here? I thought the exemption was for sales into ISO-, RTO-controlled markets. That's a different product to me than a bilateral sale that may have attributes quite similar to the attributes of the sales into the ISO- or RTO-administered markets.

To me they are different products, so the fact you would have an exemption in one doesn't mean I don't think we want the RTO market monitors interjecting themselves into -- I mean, we want them to give us a recommendation on the other markets we're doing, but I don't think the Commission yet has said that we are wanting them to somehow mitigate the bilateral markets that aren't subject to their control.

MR. SCHNELL: I would limit my comments to markets within the ISO's. However, bilateral transactions within the ISO, I believe, are disciplined. The FERC staff paper recognizes this.

MR. LARCAMP: Within the RTO footprint or subject to -- in effect the RTO-controlled products, the markets they are administering -- I'm talking about a bilateral transaction between Albany and New York City.

That's in an RTO market area, but it's not in the RTO market so that the RTO mitigation is not applicable.

MR. SCHNELL: That is correct. However, you have the alternative of simply not agreeing to that transaction and taking the RTO price. Therefore the bilateral transaction is disciplined by the existence of the RTO-monitored markets.

MR. LARCAMP: Then we're back to Mr. Ackerman's point. If I've heard him correctly, what he said was that to the extent that a buyer has an alternative between a mitigated and a nonmitigated product, it will always take the mitigated product to the extent that that price is cheaper -- irrespective of what that does to longer term infrastructure supply issues.

MR. ACKERMAN: It's free insurance.

MR. O'NEILL: I believe what you're saying is you're objecting to the potential overmitigation of the ISO, not the fact that you want your bilateral contracts regulated.

MR. ACKERMAN: No, I don't want the bilateral contracts regulated. I don't think Dan said that either.

MR. RODGERS: Are there other comments from those in the audience? Please come forward.

MS. TEZAK: Christine Tezak with Schwab Capital Markets, Washington Research Group.

I have a question as someone who is asked regularly when you're going to get around to finishing this. Mr. Larcamp, please don't leave the room. This question is directed to you.

(Laughter.)

MS. TEZAK: The question I had is, is this a screen or is this in fact a test? Where does this particular analysis come in? Before, during, or after the vertical market assessment, the barriers to entry , and the affiliated analysis that are also part of the NBR?

Are you planning to make changes to these also? What would the timeline be so that investors have an idea of when changes may be coming?

MR. LARCAMP: Yes.

(Laughter.)

MR. LARCAMP: I mean from staff's perspective, I think it's fair to say this is one part of a multi-part test for market-based rates. I don't think staff at least is, for example, ready to jettison transmission market power concerns anymore than we're ready to jettison barrier to entry concerns.

I do think staff believes that the Commission needs to take a comprehensive look at its test, to do so as quickly as possible given that the other regulatory issues that the Commission has on its plate, not the least of which now is sort of what we talk about here about bilateral service.

MS. TEZAK: Is this something where we can expect to see changes in existing dockets that are pending before you? In 6 months, in 12 months, in 2 years? Is this something we could see an interim methodology appears as early as this year?

CHAIRMAN WOOD: Since I'm in charge of scheduling these things, I'll take that one up.

We have had now pending for rehearing for over two years action on these dockets, these three. Those were joined the next week by a couple of other large companies and upped now to 74.

As I mentioned to a group from the press last week, early this week we were at some legal peril for not acting on those. We promised, in staying the action on rehearing, that we would have this technical conference.

So we are fulfilling our condition precedent for acting. And I think the quality of input we've gotten just today alone has been excellent.

I know from reading the entry comments that we asked for prior to today, as well as those that we had last year about this time, that we've got a very sufficient record to allow us to move forward on the generation screen aspect here.

I think, speaking for me, we could probably go a number of different ways. The screens are going to catch -- on account of different ways you formulate the screen, you catch different people. But I would probably guess that the SMA screen is the one that catches the most. Because it was a snapshot of one day, it's probably the broadest, the most broadly available product.

So out of 900 people who have market-based rates, you're talking about less than 10 percent that we're dealing with -- kind of like the California refund case. You winnow it down. You might not ever get through it.

But I do expect we'll get through these. We have a lot of the finite universe to deal with. We've got a lot of good guidance about different ways to slice it.

Personally, I know from talking to my commissioners here, I've gotten some good feedback that a couple of different screens -- as I think some people on this panel recommended, and the earlier one as well. A couple of different screens are helpful.

But ultimately they catch a person or company for further discussion. And I think it's kind of -- I would hope within the next couple of months we do identify those companies, have those further discussions, and identify the extent of the mitigation that we're looking at.

Tomorrow morning's panel, I think, will be very helpful because it's one thing to identify a person. I think Mr. Wroblewski is probably the most articulate on that here.

But really what you're talking about is what kind of mitigation applies. And from your perspective on the investors' side of the fence, mitigation is really where the rubber hits the road. We're got to answer those probably in the next couple of months, pretty soon.

MR. TUCKER: Russell Tucker, Edison Electric Institute. I have a question for the panel.

Traditionally utilities have maintained 15, 20 percent reserve margins. And I think it's generally perceived as efficient and effective at maintaining reliability because the SMA and CSI tests do not net out native load and committed capacity.

It appears that a reserve margin of the magnitude of around 100 percent would be required in order for some applicants to get market-based rates.

My question is, is that accurate? If so, could a competitive wholesale market support a 100 percent excess capacity market?

MR. FRAME: If I understood your question, the total capacity version of this test -- wouldn't there have to be so much surplus capacity floating around for many traditional suppliers. That just would be ridiculous, yes. That's the correct answer. And, of course, the market can't support that much.

MR. LARCAMP: Could I ask you a question. Do you agree with Mr. Henderson's comment that the operating reserve portion should not be available for sale because it's available to maintain reliable service. So I'm just trying -- I mean, the 15 to 20. Are we talking operating reserves, planning reserves? What are we talking about here?

MR. TUCKER: 15 to 20 percent. We're specifically looking at planning reserves. And typically utilities have maintained such planning reserves with regard to the SMA as proposed.

And the CSI index as proposed -- some applicants would be required to have 100 percent. The market would be required to have a 100 percent excess capacity in order for those applicants to get market-based rates.

And my question is, how can a competitive market support a 100 percent capacity margin?

MR. LARCAMP: I don't disagree with that, but do you agree or do you have a position on whether you should be allowed to sell the operating reserve component in terms of measuring uncommitted capacity?

MR. FRAME: The question is not whether you ought to be allowed to sell it. It's whether how you ought to count I think.

MR. LARCAMP: If you have to maintain your operating reserve to meet reliable operation of the transmission system, how can you turn around and sell that capacity?

I guess it is a question of how we calculate what goes into Mr. Henderson's undercommitted capacity bucket.

MR. HENDERSON: The correction would be instead of subtracting 100 percent of native load, you'd subtract 100 percent plus operating reserves.

When you make the calculation about committed capacity, it wouldn't be a question like Rod said of whether or not you're telling somebody whether they can sell it or not. It's just when you're looking at that which you think is uncommitted and available for the market, you've made the correction for operating reserves.

MR. LARCAMP: But couldn't operation -- presumably reliable operation would be -- you'd want to know if people were selling their operating reserves.

MR. HENDERSON: In the ordinary course of events I'm not an operator. But operating reserves are for the most part standby. They are not sold in the energy market.

That what's spinning and supplemental in those reserves are they are only cranked up in the event when the contingency occurs and they're needed. And they're replaced presumably, so I don't think of them as being sold routinely.

MR. LARCAMP: I guess my question, then, is normally they would be withheld from the uncommitted capacity bucket because they are committed for reliable operation of the system.

If we found out through reporting that those units were making off-system sales, then we would have a further inquiry.

MR. HENDERSON: I'm not sure I'm following the question, Dan. If you're saying if the utility is not following the NERC reliability guidelines and maintaining the level of operating reserves that they should, they have a much bigger problem. They have a reliability problem that if I were you, I would go after them on -- as opposed to some sort of market screen violation inquiry.

MR. LARCAMP: It's a question of how do we count the KW's.

MR. MARSHALL: Normally you're not going to take those. They're operating reserves for good operating reasons and they aren't for sale. Just like if you have capacity on outage. Whether it's forced outage, planned outage, long-term plan, derated -- it's not for sale. At a particular time it doesn't exist. You can't sell if you don't have it.

MR. O'NEILL: Our reliability audits would pick that up, wouldn't they?

MR. TUCKER: And EEI will respond if given the opportunity to submit post-conference comments. We're working with our members on these issues and we will respond to that very question for you.

MR. FRAME: Could I just add one comment on the operating reserves. I'm not convinced that operating reserves is the right concept to crank into the screen measure.

And when you're asking the question how much might someone have available to sell, they may not sell down just to the bare bones operating level. There might be a higher level above that operating reserve margin that they won't sell below, depending upon the time that the question was asked and what things looked like coming up ahead.

If you're talking about the answer in July, it might be a different answer than the answer that you get in April. But looking from April forward across the summer peak, they are probably going to want to hold something a little above that operating reserve level to account for all kinds of other factors.

MR. LARCAMP: Then it would be appropriate for us to ask applicants to specify those megawatts that they are withholding for reliable operation in terms of calculating what's available to meet market demand.

MR. FRAME: I think you can certainly put the burden on applicants to discuss the different components of their reserve margins.

MR. RODGERS: Our last questioner.

MR. HAGEDUS: Mark Hagedus with the law firm of Spiegel and McDiarmid, counsel to the American Public Power Association and the Transmission Access Policy Study Group.

I actually have a comment and a question. My comment stems from my four years in the antitrust division of the transportation, energy, and agriculture section. I was there up until a year and a half ago.

Just based upon some of the investigations I worked on there, I had a couple of reactions to some of what's been discussed today in terms of how we dealt with some of the issues that I think we've been talking about here.

In the investigations I dealt with there one of the issues just has to do with this question of the market monitoring units in the ISO's and the RTO's and what effect that had on our investigations.

I agree with Mike Wroblewski that having and having ISO's and RTO's was tremendously helpful in terms of our ability to carry out the investigation because we were able to obtain a lot more information about the market.

Did it make a difference in terms of leniency or the vigorousness with which we investigated the company? No, it didn't matter whether they're in an ISO or RTO or not. They are equally subject to the antitrust laws.

And that might be something you want to take into consideration in terms of whether or not when you apply your market power screens the market power is going to exist on a horizontal level whether or not they are in an ISO not.

The second point has to do with the removal of capacity that is dedicated to native load. The way that came up in some of the investigations I worked on, we thought about -- you could think about that as internal consumption on the part of the firm.

And in our experiences we did not eliminate that internal consumption, the capacity associated with that internal consumption from our screens. For our HHI analysis, for example, we left it in there because of the fact that it remains a factor in the dispatching decisions of the firms.

And in fact I think we heard some of that here today. And so it would be incorrect to take it of the screen analysis. You might take a look at it and try to figure out what did the screens tell you about your market and what does that fact that there is a native retail load that's under rate-base regulation.

But you need to have a story. You need to understand what role that plays. And you do that after you've done the screen and taken a look at what your market looks like as a structural matter.

My question actually is to Mr. Frame. He had indicated if capacity that's dedicated to native load isn't counted, he didn't think it was a good idea then to sort of set that capacity aside and prevent it from making sales into the wholesale market.

I think, Mr. Frame, you indicated that would not be a good idea because I think you said it was not pro-competitive. I'm wondering if you could explain to us more about why you didn't think that was a pro-competitive step to keep that capacity out of the wholesale market.

MR. FRAME: I think it was pointed out that perhaps -- and I'm not certain, but perhaps I misinterpreted the test that was offered earlier.

What I was interpreting as was that some amount of capacity that was deemed to be dedicated to retail load based upon some peak measures would in fact not be needed for the retail customers during some nonpeak times.

That capacity would not be allowed to make wholesale sales during that point in time, and during those off-peak times or nonpeak times. Therefore that capacity would lie idle. That's just strikes me as tremendously wasteful.

And if you draw your supply and demand curves, if you take some supply out of the market, the prices are going to rise. And when the prices rise, that's what I call anti-competitive. It's harmful to customers.

MR. HAGEDUS: So that's supply in the wholesale market that we're looking at.

MR. FRAME: My assumption when I answered the question was that the supply would not be in the wholesale market and therefore the supply would be less and the prices would be higher.

MR. HAGEDUS: Would you agree, then, that the prices go up when you withdraw because in fact that suggests that that supply is a factor in the wholesale market that we're looking at.

MR. FRAME: The prices would go up when you withdraw supply.

MR. HAGEDUS: What about -- would you agree that there might be some other aspect on another slice of the capacity that you could completely exclude from the wholesale market?

MR. FRAME: I haven't agreed that you ought to do this, that you ought to restrict this capacity from being made available to the market.

MR. HAGEDUS: Why not?

MR. FRAME: Because it is pro-competitive to make the capacity available to the market and it is wasteful for it to lie fallow.

MR. HAGEDUS: That's because the capacity does play a role in the marketplace. If you withhold it, the prices go up.

MR. FRAME: There's no question that when capacity is withheld, prices can rise. That's not -- of course, market power by itself -- there's much more to the test. Is it profitable to do that?

But certainly if you move along the supply curve, you can get some price increases if you withhold it.

MR. HAGEDUS: Thank you.

MR. RODGERS: Thank you, Mr. Hagedus.

That concludes our panel for today, our discussions for today.

I want to thank very much this excellent panel that we had this afternoon for very, very helpful comments. I appreciate your taking the time to appear before us.

We'll reconvene tomorrow morning at 9:30.

(Whereupon, at 4:30 p.m., the conference was recessed until 9:30 a.m. the following day.)