BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Numbers

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

Wednesday, January 14, 2004

The above-entitled matter came on for technical conference, pursuant to notice, at 9:30 a.m.

BEFORE:

STEVE RODGERS (OMTR), presiding

APPEARANCES: (AS HERETOFORE NOTED.)

P R O C E E D I N G S

(9:30 a.m.)

MR. RODGERS: If I could have your attention, please. Why don't we go ahead and get started this morning for our third panel on the supply margin assessment technical conference.

This morning's panel is focused on what is the appropriate mitigation that should apply for those that fail the generation market power screen that the Commission is in the process of developing.

Among the topics within that topic that we'll be focusing on are whether the Commission should focus on cost-based mitigation; single market clearing-price mitigation; whether there should be a generic area wide rate cap, for example, that should apply; whether mitigation should apply in the short term only or whether it should also apply in the long term.

In various other subjects related to that, as was the case with the panelists yesterday, I've asked each panelist in today's two panels to feel free to address any of the topics covered in the panels before us after they've taken some time to address the topic of panel that they are on.

One procedural change I am going to make compared to the way we did things yesterday -- what I'm going to do today is have each panelist give their remarks in order. Then we're going to have Q and A opportunity.

So we will proceed straight from Dr. Hieronymus to Bill Dudley and so forth and so on, then have an opportunity for Q and A from Commission staff and Commissioners and then ultimately from those in the audience.

With that let me introduce Dr. Bill Hieronymus, the Vice President of Charles River Associates. Welcome, Dr. Hieronymus.

MR. HIERONYMUS: Yesterday, two things came up that got some traction.

One was the notion of multiple screens. I'm not per se opposed to multiple screens. I'm not sure that we know what we're doing entirely. I am concerned on the precedent of the Section 205 multiple screens. Having multiple screens means you have to pass all of them. If the end result of multiple screens is that we simply carve down the number of people who have market rate authority pointlessly, I think it's a very bad idea.

The second thing I wanted to comment on was this notion that you might get market rate authority for some of your capacity, but not for the rest of it.

The notion specifically was, if you measure it at the time of system peak, you've only got a few hundred megawatts of uncommitted capacity; but at other hours you've got a lot more, you should somehow or another get market rate authority for the few hundred megawatts but not for the rest.

That strikes me as a remarkably bad way to approach the problem. If the Commission has a problem or a concern about market power away from peak, the right answer is simply to do the right test for nonpeak conditions. And whatever passes, passes. Whatever fails, fails.

I think this notion of bifurcating capacity -- even if administratively feasible, serves to do nothing but reduce the amount of capacity that's sold at market rates during the periods when most of that capacity -- when there's a lot more of that capacity chasing load. And those should be the cases where we're less concerned rather than more concerned.

That having been said, I think everyone should declare their vested interest when they talk at these conferences. CRA has clients, both very long power marketers and IPP's and very short utilities.

Excelon, who's sponsoring my comments, has a very short utility in ComEd and a very substantial power marketing function. So we don't care in that sense.

My true vested interest is that CRA, my colleagues Dr. Henderson and Ms. Solomon, and I do more SMA analyses than anyone else. We've done more mitigation schemes in the context of 205 than anyone else.

So our vested interest is in complicated tests and a lot of consultant input.

(Laughter.)

MR. HIERONYMUS: It's very, very hard to design mitigation schemes. There's our vested interest.

Let me begin, then, by simply noting that the goal of any screen and associated mitigation should be to preserve and protect the competitive elements of the wholesale market. To the extent we can avoid it, we should not be simply retrenching to cost-based rate making.

Second, the necessary form of mitigation flows from the identified market power problem. A number of commentators have suggested that the right way to look at a wholesale is with uncommitted capacity and uncommitted load. I took that position in my filed comments also. If the Commission adopts that position, then an easy way to mitigate is to make the problem go away. You can make the problem go away by either putting the load under contract or putting the capacity under contract or doing both simultaneously and therefore just eliminate the problem.

You can't do that if this an installed capacity test. Even if the utility were willing to go as short against native load, it would be implied by doing that. I very much doubt that their state commissions would go along with that.

With that test there is no natural way to mitigate in order to achieve the market condition which has been designed to cause to come into being.

I also note that if you look around the country, market conditions vary substantially. You've got the RTO's, which are at most moderately concentrated. You've got the market-power mitigation in place. You've got some local market power problems.

But in my view we best leave mitigation to the market monitors for supervision.

In the South you've got big vertically integrated utilities, no state interest in retail access, a lot of merchant capacity looking for a home.

In the West you've got a lot of free flow of electrons. If not over the entire West, across broader regions you will see they have a lot of energy-limited capacity. That just makes designing mitigation schemes very difficult.

In the Midwest you've got proto-RTOs, relatively unconcentrated markets. And it's a whole different kind of fleet of generation. You've got different underlying market conditions. We would expect to see different kinds of market power problems.

The other thing I want to emphasize is that the cure shouldn't be worse than the disease. We have enough experience with various things in the context of reconstruction to know that whatever we do has consequences.

Mitigation should be draconian only if the market power problem it is meant to solve is substantial. It shouldn't be a hypothetical or theoretical market power problem.

Recall that for the first several years of deregulation we had a toothless hub and spoke test. And then we came up with SMA, which had some teeth. Maybe the wrong teeth, but it had teeth.

However, we immediately put in abeyance mitigation, so for the last couple of years there's been effectively no test at all. Query: how badly are markets performing?

The only market that seems to have been problematic is California. California has an RTO. It's structurally unconcentrated.

The only people that have failed the screen in California were Edison and PG&E. And, of course, they were big net sellers, not big net buyers. Sorry -- I've got that backwards obviously.

I will say one other thing about California, which is that California teaches, I think, the lesson that market problems have to do with the characteristics of markets, not with the characteristics of individual participants.

And, of course, this test addresses the characteristics of individual participants. Now, which is preferable? Cost of service or single market price? I note that the industry seems to prefer the former. I think they do so frankly because they think the rates will be higher.

I can't tell from the staff's paper whether that's true or not. The staff's been relatively sketchy about what kind of capacity would be included in the market rate, whether its the marginal capacity available to some of the wholesale market or whether it's total fleet that runs at time of peak. That will have fairly profound effects for what the rate looks like.

I will note that irrespective of what the form of the test is, if it's cost based it's going to be a big burden on staff and a big burden on applicants.

Most merchants have never done a market rate filing. An awful lot of utilities haven't done one in 10 years, including at the state. So if you open up 74 failing utilities, to use the Chairman's number, to have to do market rate filings, you are opening up a pretty good sized can of worms.

Also for utilities that have been restructured we have the problem of where their costs lie, the generation costs, because stranded cost treatments are often in their distribution rates, not in the generation pot.

The second major concern I have with cost-based rates is that any average rate kind of concept is going to lead to a rate that's probably higher than market much of the time and therefore irrelevant. Nobody will buy it. And lower than market in times when the system is stressed.

So the utilities, the seller subject to that rate is going to be getting lower cost than market pricing. That's bad for that utility, but I think it's even worse for the market.

If the end result of that is all the market peaks are clipped, then we don't get the price spikes that we need to induce new entry or induce demand-side response.

The single market-clearing-price approach also has a lot of difficulties that I have listed out in my prepared comments. Staff has made, I think, significant progress since last fall in developing this approach.

When I think if those could be solved, it's a better solution than the cost-based approach. Staff specifically suggests some kind of an annual cost kind of revenue camp as a possibility. If you did that, you could avoid this price clipping I just alluded to. And that might be a good thing.

Staff does continue to propose a requirement that the mitigated firms both buy and sell at market-clearing prices. This creates a kind of quasi day-ahead market in places where no such market currently exists.

I can appreciate that that may be a very good thing for obvious reasons. However, from the standpoint of market power mitigation, to require that a utility that fails a test of seller's market power, buying from a market at mitigated prices is unmotivated.

Irrespective of the form of the tests, one of the questions that the staff hasn't answered is, who gets to buy at the mitigated price? The failure is always going to be in the control area, where you have a lot of generation.

Today really most buyers are not in that control area -- most wholesale buyers. They are people serving load in neighboring jurisdictions. Are they going to be allowed to buy at the mitigated price merely because they take title at the bus bar?

That's sort of a free ride for them and they are in there competing with a wholesale load that actually is in the control area.

I don't have a view of that, but it's an issue that has to be addressed. We are asked whether it's sufficient to mitigate spot prices or whether we need longer term price mitigation.

I think the answer is, it probably is sufficient. We're all familiar with the argument as to why spot prices mitigate longer term prices, but that's really not my reason.

My reason is a pragmatic one. If we're talking about longer term, we mean time enough to arrange new contracts with merchants, arrange for new entry. That market is inherently competitive.

This situation could change if instead of having a few hundred megawatts of muni load that isn't under long-term contracts, we've got substantial retail access.

But it seems to me very unlikely that you're going to get a lot of retail access in areas that both lack an RTO and haven't restructured the ownership or generation.

We're asked whether there might be other preferable approaches. I'll just briefly note some possibilities.

One would be that an applicant could make transmission available to the muni load so they could access wholesale, competitive wholesale markets outside of themselves. We've proved something like that in Virginia for the retail access pilot.

Another would be to offer option contracts on a price-taking basis so you say, all right, we'll make enough capacity available at a market-determining price to serve the existing wholesale load in the control area.

That will only work, of course, if there are multiple bidders. Otherwise we're just telling the one guy who could access or the two guys who can access that you can get it for nothing.

A third approach, which is my favorite, if it can be done, is to tie mitigation prices to a reference bus outside the control area. The problem we have, of course, is that other than NTS Energy and into Entergy there are relatively few liquid trading hubs.

A more general application of that mitigation would require that FERC have a program of collecting data that would allow them to see what transaction prices were in places where they are not visible from the existing sources.

Should failing entities be allowed to propose their own mitigation? My short answer is yes.

Again, my reason is pragmatic. We don't really have a firm idea of what good mitigation is because we don't have a firm idea of what the problem is.

I think this is a case for letting a thousand bloom. That would be a good rather than a bad thing.

Staff will obviously have to exercise its discretion and the Commission its discretion over what works and what doesn't work.

I note that that's a short-term rather than a long-term solution. I kind of doubt --

To close I think there's a lot of market power being exercised in these unorganized markets. My concern over unintended consequences leads me to reiterate that we should not make the cure worse than the disease.

The Commission's long-term preferred solution to market power is RTOs. The fact that RTOs have been stalled somewhat shouldn't cause us to go back and wholesale rate-regulate the wholesale market and indeed to engage in the sort of micromanagement of bidding behavior and offeror behavior that didn't even exist in the previous world.

If we do that, we simply will stifle the kind of development of competitive markets that is the Commission's goal.

Thank you. I have about 50 copies of these remarks. I wasn't so arrogant as to assume that everyone would want a copy. But I'll leave them up here.

MR. RODGERS: Thank you, Dr. Hieronymus, for those thoughtful comments.

Our next panelist this morning is Bill Dudley, the Assistant General Counsel of Xcel Energy Services.

Welcome.

MR. DUDLEY: Thank you.

Just a word about Xcel Energy or the Xcel Energy companies. I can't say it's unique anymore, but it is somewhat unique in the geographic reach -- the system, it has two companies, Northern States Power and Northern States Power Company Wisconsin, which are located in MAPP.

Also in MISO it has Southwestern Public Service Company, which is in the SPP. Then it has yet a fourth primary operating company, which is in the western interconnect, in WECC, the Public Service Company of Colorado. So we hit a lot of regions.

That said, Xcel Energy believes that the industry will benefit if the Commission and this proceeding can develop and adopt an appropriate backstop mitigation approach that will apply in the event a utility fails whatever market screen the Commission ultimately adopts.

The purpose of this presentation today is not to address that screen. But my frame of reference is you're dealing with a situation where the assumption is you're dealing with a situation where a utility fails the screen and what to do.

As to what constitutes an appropriate mitigation approach, we indicate in our written comments that we believe the must-offer requirement at split the savings price seam is inappropriate.

We suggest a couple alternatives for the Commission's consideration, namely an appropriately-derived up-to rate or, alternatively, some kind of a regional rate cap.

Today, rather than simply summarizing written comments, I thought I would try to talk about some of the philosophical underpinnings of our approach.

First, Xcel Energy has no objection to the Commission's focus on the spot markets for purposes of mitigating market power. However, as the Commission pushes towards its goal of fostering greater competition in the industry and wholesale markets, it should, to the greatest extent possible, provide for a level playing for market participants in all relevant markets, including the spot market.

The Commission itself has noted this goal as one of the bases for its SMD initiative. In many ways the Commission's proposed mitigation measures provide for the creation of individual markets like the SMD does, but in this case, anchored by those utilities that failed the Commission's ultimately adopted market screen.

Unlike SMD markets where everyone within a region would be required to play by the same rules, in these markets only one entity, the utility that is unfortunate enough to fail the screen, would be required to play by any rules.

The result is a market where the benefits will flow only one way and where the capacity value of resources by the failing utility is captured and transfers to others without appropriate compensation.

Under the proposed mitigation requirements the purchaser has no obligation to supply energy back to the selling utility on a reciprocal basis. It's a particular concern of the Xcel Energy companies who operate in regions where there is a strong nonjurisdictional entity presence.

The level-the-playing-field problem is further compounded by the fact that the must-offer requirement would appear to require sales on energy at mitigated prices to any entities, not just for loads in the relevant market.

Bill Hieronymus, for example, pointed out the problem of sales at the bus bar, which is one of the things that we noted in our written comments. That is, in fact, the way a lot of transactions take place these days.

The effect of the mitigation, if it's not corrected, would be to allow basically a utility outside the region where the utility has been found to have market power, where they can come in, buy power at the bus bar and basically take the power outside the system and arbitrage it.

The second philosophical point is that Xcel Energy believes that the Commission must not encourage purchasers to free-ride by over-relying on spot markets.

In this regard the Commission and its SMD initiative proposed various measures to reduce over-reliance on the spot markets to insure that load-serving entities maintain long-term resource adequacy.

That, however, is not an aspect of the mitigation that the Commission is proposing in connection with the SMA. Commission staff posits that lower price energy in the spot markets will lead to lower prices in the long-term markets, which will in turn lead to more forward purchases because entities, they theorize, will want price certainty.

Xcel Energy believes there's a simpler and more direct consequence that will follow, which is low price energy in the spot market will encourage utilities to rely on the spot markets.

The third philosophical point follows from, and is a partial solution to, the other two. If the Commission is, nevertheless, going to require as mitigation the one-sided sale of energy to the spot markets, it needs to get the compensation scheme right by allowing selling utilities to obtain a price that adequately compensates them for having capacity available to be sold into the spot market and which will require purchasing utilities to pay closer to the true value for that power.

Split the savings price seam does not meet that standard in our view. In fact, it is less than what the Commission has historically allowed under the cost-based regime that applied prior to open access.

The cost-based standard for a coordination sale has entitled utilities to recover 100 percent of their incremental costs plus a contribution of up to 100 percent of the fixed costs of the units supplying the sold energy.

Moreover, also in the Commission's cost-based regime, the Commission has historically allowed utilities to charge $100 per megawatt hour for emergency power even though that amount was often above or could have been justified by a focus on the selling utility's costs.

When the standard was developed, the Commission probably wanted to incent utilities to have the capacity and to make the energy available to be sold for emergency purpose, but also wanted to disincent purchasing utilities from leaning on the systems of others.

It bears emphasis that for most purchases operating under normal system conditions, the spot market, at least that of certain organized RTO markets, is an economy market. And they have alternatives to making purchases in it.

In those instances where purchasers buying the spot market because they are shot in capacity either because of some temporary system problem such as loss of the unit or because they failed to plan adequately -- in either case they are in essence getting the capacity benefit when they purchase in the spot market and they should pay for it.

For these reasons Xcel Energy suggested two alternative pricing mechanisms in its written comments for the Commission's consideration.

One would be a regional price cap set sufficiently high to compensate the selling utility for the capacity benefits that it provides.

Alternatively, Xcel Energy suggested a cost base up to -- that again appropriately factors in capacity costs.

We believe both these alternatives are consistent with the Commission's pre-open access pricing methodologies and will be infinitely easier to administer than the proposed split-the-savings approach. Either of these approaches should also lesson the free-riding problems.

Thank you for the opportunity to speak. I'll be happy to answer questions later.

MR. RODGERS: Thank you, Bill. I appreciate that. Our next panelist is Pat Alexander, an energy industry advisor with Dickstein Shapiro Morin & Oshinsky and I might add a long-time clerk staffer with lots of experience on cost-of-service rates. Welcome, Pat.

MS. ALEXANDER: Thank you, Steve.

Let me just start by saying I'm here giving my personal opinions today and not those of the firm or any of our clients.

As Steve said, he asked me to participate in this panel because of my experience with what's called in the strawman mitigation measure traditional cost-based rates.

Specifically the staff paper refers to up-to rates. As Bill mentioned, that's a rate that reflects the incremental cost incurred as an adder of up to 100 percent contribution to fixed costs.

I thought I would focus my remarks on how those up-to, cost-based rates came to be designed. Up-to rates were used to price what were called opportunity transactions between traditional vertically integrated utilities serving bundled load.

There were no competitive suppliers to power marketers, no power marketers, no merchant generators. But from time to time neighboring utilities had the opportunity to enter into mutually beneficial trades with each other.

The question was how to price those trades.

The only costs that were incurred were incremental costs. Since there were no fixed costs incurred by the seller, there was really no basis to allocate fixed costs to these transactions. Yet fairness dictated that the seller be allowed to recover some amount above incremental cost.

Since native load had already been allocated to all the fixed costs, fairness said the buyer should make a contribution to those fixed costs when it purchased under an opportunity transaction.

The up-to rates appear to reflect the maximum 100 percent contribution to those fixed costs spread over the number of hours in a year.

The bottom line of the story is that these were sales from one set of rate pairs to another set of rate pairs and where the rate-making theory was one of fairness and equity, not competition in markets.

Split savings rates are made from the same cloth. It was fair for the rate pairs of one IOU to show the benefits of the trade equally with the other IOU's rate pairs. Since the industry is clearly in a different place today, the value of resurrecting these rate designs is not apparent.

I guess the broader question today is whether cost-based price caps are useful mitigation tools in today's environment. Here the story is even simpler. Cost-based regulation works when it is both a cap and a floor.

When the cap and the floor are identical, there may be some sellers in the marketplace that do operate with such floors. Mr. Marshall explained yesterday that the Southern companies pass all their revenues onto the rate payers. But for many sellers there's no assurance of cost recovery.

These competitive suppliers under market-based rates are not entitled to such assurances. They are simply entitled to charge the market price.

Market prices can be above or below the sellers own cost at any point in time. And a cost cap will only intervene on one side of that equation. Cost-based rates did not profess to or come close to replicating competitive prices. That's why we're going down this road now.

If the goal is to promote competitive markets using cost-based rates, to mitigate competitive prices seems to me to be a walk in the wrong direction.

With that I'll answer any questions.

MR. RODGERS: Thank you, Pat.

Our next panelist this morning is Don Sipe, counsel with Preti Flaherty. He's been asked to appear on behalf of industrial customers today. Welcome.

MR. SIPE: Thank you, Steve.

I'd like to make some comments first about the split-savings and cost-based approach. But the majority of my comments will be in other areas.

I think it's reasonable to adopt cost-based mitigation methodology when we presume that we have market failure. I think many of the comments we heard sort of presume that the conditions of market failure don't exist and therefore there is some viable alternative to sort of a cross-based mitigation that isn't arbitrary.

I think it becomes harder and harder to find a nonarbitrary standard. When we've once admitted that we have market failure, I think that some marginal competition is still allowed under a split-the-savings approach.

That is generally where a lot of the competition ought to be occurring and would be occurring if the economic model of the competitive market were actually in effect. People will compete on their incremental costs. And you will only make up the capacity cost and sort of the difference between being the marginal unit and the inframarginal units.

There are implementation issues that need to be addressed, but theoretically the split-the-savings methodology makes some sense given the premise that we have market failure and that other modes are not based on anything in particular -- setting a particular cap somewhere, for instance.

Scarcity pricing, if it's scarcity pricing in the sense of we have gone to the highest incremental cost unit running, that sort of "scarcity pricing" is going to be captured by the staff split-the-savings model because obviously the higher the incremental costs get, you'll still keep moving up the curve.

If it's scarcity pricing in the sense of scarcity pricing because we're simply out of resources, I think scarcity pricing without adequate demand response is just profiteering in necessities.

There isn't any reasonable way to set a scarcity price in the absence of demand response, which has some disciplining effect on that.

The scarcity pricing that I'm hearing touted -- we're presuming again that we are in market failure. Talking about scarcity pricing as a tool when we have market failure is a bit anomalous to me.

With those comments I'll move on to some of the other areas I'd like to cover today. I want to spend a little bit of time talking about some of the structural changes that were suggested by the order, which I think in the long term are going to be more important to consumers than whatever short-term price mitigation we may effect.

Obviously if we can't find the right to short-term price mitigation we can simply not do market-based rates until we get some of these structural problems fixed. I would urge the Commission not to be afraid of doing that.

If in fact we can't find a price-based mechanism or some reasonable price mitigation mechanism, that some of the structural remedies that were suggested in the order, I think, will lead the way to putting us in a position where the industry gets to a place where mitigation and market failure are no longer an issue.

One of the major remedies that I think has received less comment than is due is the interconnection requirement that was in the SMA order. That interconnection requirement essentially should be structured in a way that allows a new unit to interconnect by preserving the stability, reliability, and transfer capability of the existing grid and then should allow for competition through displacement.

I think that is certainly an appropriate measure as a mitigation measure. But I also think that it is an appropriate measure even where a participant passes the market screen and is asking for a market-based rate authority.

I think that type of reduction to barriers to entry is a structural necessity if you're saying you want to price at market-based rates because obviously market-based rates have to be disciplined by the threat or actuality of new entry.

As long as we are still using a standard which essentially requires people who want to compete on the highway of commerce to build their own highway, which is what I believe many of the deliverability standards currently in practice amount to, we are creating an uneven playing field, which will not allow price discipline for new entry.

That is a structural change that needs to be made. The key to the standard is allowing competition through displacement. By doing that, you allow the new entrants to use the existing capacity of the transmission system to compete with incumbent resources.

Native load is still going to get served. We don't need retail access to make this kind of competition a reality.

An incumbent utility who has generation should be looking for cheaper sources. If those sources come in with incremental costs below their own incremental costs of production, they can buy it wholesale and should probably be required by their Commission to buy it wholesale from a cheaper unit that comes on and then serve those same native load customers at retail with their wholesale purchases.

So there is not a need for retail competition for this to be important and there is not a risk that native load customers will not be served.

I think the other area that is much simplified by the simpler interconnection standard, which was suggested in the order, is that the issue of participant funding or the lack of it is much less when the proper facilities for a competitive interconnection are considered.

Needlessly expanding the grid to expand the capacity of the grid every time a new competing resource comes on and then saying that that needless expansion of the grid creates price hurdles that will harm it if loader can be used as a barrier for entry to the new entrant is sort of putting the cart before the horse.

The question that I think was answered properly by the SMA order is focusing on what sorts of facilities actually would need to be built.

If you focus on the facilities that don't require you to have some separate mode obligation lined up, but allow you to enter the utility system and to compete for existing capacity on the basis of your incremental cost, I think the facilities that need to be built will only be those necessary to connect the generator reliably to preserve stability and not degrade transfer capability.

That's a much smaller bill either for consumers to pick up or for the new entrants to pick up than the traditional, as I call it, build-your-own-highway approach to interconnection.

I think other structural remedies suggested by the order are just as important although I'm running out of time to talk about them. I'd be happy to do it on Q and A.

I think the independent administration of the OASIS system is another important piece that is a structural change which would allow greater confidence in the market and should be pursued.

As I said, I do have comments and further comments on price mitigation. I'd be happy to answer questions later on. Thank you.

MR. RODGERS: Thank you very much.

Our next panelist this morning is Robert O'Neil, the general counsel with Golden Spread Electric Cooperative. Welcome.

MR. O'NEIL: Thank you. It's a pleasure to be here.

I have had the opportunity to speak before the Commission before and oftentimes it has been in a more generic context. Today I'm going to limit my comments to really the implications of this particular topic on Golden Spread Electric Cooperative.

By way of background Golden Spread Electric Cooperative is a FERC-jurisdictional cooperative that became FERC-jurisdictional in 1987.

It started out with 11 members. As of just a few months ago the membership has increased to a 16-member cooperative, who need about 1,000 megawatts of load, 200 in ERCOT, 800 in the Southwest power pool.

The vast majority -- by that I mean about 790 megawatts of that 800 -- is on the system of Southwestern Public Service Company, which is an Xcel operating company.

I've had a lot of dealings over the years with Bill Dudley. Given our relationship in terms of the geography, I expect to have a lot more in the future.

Now, Golden Spread's power supply to serve its load obligations consists of about 480 megawatts and a generating plant that was caused to be built.

380 megawatts and a partial requirements contract with Southwestern Public Service Company under the new members has about 150 megawatt, full requirements contract with Southwestern Public Service Company.

Southwestern Public Service Company has served notice of termination on the 150-megawatt contract, with the termination to take effect 12/31/05. SPS has served notice of termination of the partial requirements contract with the termination to take effect in approximately 2012. It puts a pretty big hole in the supply picture.

Golden Spread has no intent or desire to be a free-rider so it goes out and says, okay, how do we plug these holes? What's the market?

Well, the market in the Panhandle has about 4,000 megawatts of generation, which is about Southwestern Public Service Company generation, about 480 that's Golden Spread and a few other cats and dogs floating around the system.

What's the transmission picture? A very, very limited transmission import capability. In fact, the chairman of Xcel, Wayne Brunetti, publicly stated that he didn't think that the Panhandle would be competitive because, among other things, of the transmission limitations.

Recently I had a meeting with the transmission function of Southwestern Public Service Company on the basis of here we are, a network load. And one of the responsibilities is for the transmission function presumably to plan for the transmission needs of the net worth load.

Well, how do you plan for the needs? What became clear is that from the transmission function standpoint, they take a look at the load projections of the various network customers' native load, et cetera. And they take a look at the generation in the area. And if there's enough generation for the load, there's not a transmission problem. If there's not enough generation there for the load, then they assume that a generator will be built somewhere, that it will work without having to built the transmission.

Oftentimes that might be the existing power plant site of the incumbent utility. So if you have out in the future period a 330-megawatt loss of resource for this wholesale customer and a 330-megawatt recaptured capacity by the incumbent supplier, there's no need to build transmission.

Why? Because you can always buy from the supplier who's got the 330 megawatts that they just recovered.

What do you pay? Well, I sat here, as I look in the mirror, and I see less and less hair each day. I remind myself how long I've been in this business. And it's just recently that the notion of a cost-based rate is being somehow a confiscatory rate.

For years the thought was that cost-based rate was a just and reasonable rate. It seems to me you can have rates that either do not recover your costs -- they recover your costs or they recover more than your costs.

The notion seems to be that a competitive rate is one that will allow you to recover more than your costs and somehow you will do a terrible disservice to the sellers if you deny them the ability to recover more than their costs even if, for purposes of this panel, we must assume that they have been found to have market power.

You have found that you don't have a competitive market. Now, one of the reasons that Golden Spread was formed and one of the reasons that it undertook to construct generation is it saw risk in the future.

One of the major risks that it saw in the future was regulatory risk. The regulatory risk that it saw in the future was the risk that the regulators would regulate -- was the risk that the regulators would simply abandon regulation and leave customers at the mercy of generators or people who control generation and would thereby simply allow them to be subjected to fundamentally unjust and unreasonable rates, which are characterized as just and reasonable because they are "competitive rates."

Now, when you look at the remedies that may be available, when you have found a situation that is not competitive from the public policy standpoint, is it in the interest to require a utility to sell at less than its cost?

No. Golden Spread does not believe that there should be free-riders out there. There is no such thing as a free lunch. Someone's going to have to pay the bill. Everyone should be required to pay their just and reasonable rate.

Is there a public interest purpose in requiring a customer in a noncompetitive market to pay a premium above cost. It seems to me that what will happen is you will create a tremendous incentive for oftentimes a vertically integrated utility, which ultimately controls transmission planning as well, to seek to preserve its position, where it will have generation dominance.

The market alternatives will be limited. It can price its product at perhaps slightly less than the incremental cost of putting in more generation, which would keep out the market entrance, but yet above what would be a cost-based rate.

I would suggest and urge you to consider that we should not look at cost-based rates as somehow confiscatory rates. We should recognize that perhaps requiring an entity with market dominance to sell at cost-based rates may create opportunities for others to enter the market. Indeed, they may lose market share.

But isn't that supposed to be the objective?

I'm available for questions. Thank you.

MR. RODGERS: Thank you very much, Mr. O'Neil.

Our last panelist on this panel is Craig Roach, a partner with Boston Pacific Company, and who has provided consulting services for independent power producers, among others, in the market. Welcome.

MR. ROACH: Thank you, Steve. Good morning, everyone.

Let me put my comments in some context here. I believe that the Commission should make its decisions and have them all driven by policy goals.

I think we could probably agree that one important policy goal and one thing we're trying to do here is to use competitive forces to get the best deal possible for consumers in terms of price risk and reliability.

Market power measurement and mitigation are just two tools among many that we can use to pursue that goal. I want to emphasize that they are just tools. They are means to an end.

This Commission in all the time I've appeared before this Commission has seen them as means to an end. And I look back at one of the first cases in which the FERC used market power to drive competitive reform. It's the 1988 PacifiCorp merger case.

In that case several important decisions were made about how to look at market power. For example, it was decided that we should view transmission as a separate product market. While that decision had technical merit, it was driven by policy goals.

At that point in time it was known that the major impediment to moving forward with competitive reform was that the Commission didn't feel it had the authority to order open access for transmission.

So that decision was driven by the goal to remove that major impediment. Today -- and I mean literally today, 2004 -- I see the major impediment to moving forward with competitive reform as foreclosure of competition in the wholesale markets, longer term wholesale markets to buy power to serve native load outside of RTO's.

By long term I mean contracts, wholesale contracts, for multi-month periods, multi-year periods. By foreclosure I mean that there is either no opportunity to compete, no competitive solicitation, no forum in which to compete.

Or if there is a competitive solicitation, embedded in the rules of that solicitation are some biases that lead the results to favor the local utility or to favor its affiliates.

This is no news I'm sure to the Commission. It's one of the reasons the Commission has so many affiliate transaction cases before it -- affiliate PPA's, affiliate asset acquisitions. And I'll tell you it's no surprise to the states. Their dockets are full of these kinds of cases also.

Given that context, what should we do about measurement and mitigation of market power?

First, as far as measurement goes, while I have conceptual issues with SMA and would encourage us to move forward to a system based on market share, at the moment as a practitioner it seems to tell the right story.

I'm much more concerned about what we do when a screen has failed. What I'd like to see and recommend to the Commission is that what mitigation we propose addresses head on this foreclosure issue.

My recommended mitigation is this: if an applicant fails the SMA or other screen and that applicant is responsible for procuring wholesale power to serve retail-regulated customers, that they be ordered to design and implement a competitive solicitation. Again, it's meant to address head on that foreclosure issue.

I would encourage the Commission to set minimum standards to say what kind of solicitation meets the mitigation goals. And we should let that be driven by practice, by lessons learned. We should let it be driven by what we learn serves the consumer, what gets them the best deal.

Today I would offer five standards from our experience out in the front lines.

First, the process has to be a collaborative process, meaning that all parties -- consumers, suppliers, the utility -- all have a substantial opportunity for input on all elements of the solicitation.

Secondly, I would recommend that the solicitation from product design through bid evaluation be overseen by a third party independent monitor hired by and beholden to the state commission.

Third, all bids -- affiliate and nonaffiliate, utility and nonutility -- must be evaluated by identical criteria. That sounds obvious, but as a principle it needs to be stated.

If at all possible, if we can settle on nonprice criteria and standardize them beforehand, the bid evaluation where it's price only is preferred. That's the most transparent way to do these solicitations.

Fourth, all winners must sign pay-for performance contracts -- affiliates and nonaffiliates, utilities and nonutilities. In today's market cost plus rate-making is simply not the best deal consumers can get. It's too risky for them. It imposes too much risk.

Fifth and finally, all bidders into the solicitation must have equal access to timely and accurate estimates of what it will take for them to be a network resource, a resource that can serve native load reliably.

Today I think the most important exercise or abuse of transmission market power is that network resource status is conferred more readily on affiliates than on nonaffiliates.

Let me close with two implications in the context of mitigation -- two implications of what I've said so far for the measurement standard for the SMA. There are two points I'd like to make.

The first is, it's very important, I think, that the Commission continue to use installed capacity as the measure in the SMA test. Don't move on to uncommitted capacity.

I have several reasons for that, but my primary reason is that if we shifted to uncommitted capacity, we would simply be exempting native load from retention. And we would not be able to address the foreclosure problem that I see.

Secondly, we all have to work to change something in the SMA -- and in fact in all the screens. Right now in all the screens there is no difference in competitive effect.

If a utility itself builds its own 500-megawatt power plant or it goes out and goes through a transparent competitive solicitation, signs a 500-megawatt PPA with a nonaffiliate, that 500 megawatts still adds up to market share for that utility.

Clearly they consumer is better off if the PPA is won through a market-testing, competitive solicitation and they've really proven themselves to be the best deal.

With that let me just thank you for listening. I'd be happy to answer any questions.

MR. RODGERS: Thank you very much.

Questions?

QUESTIONS & ANSWER SESSION

MR. PERLMAN: Can I follow up with you, Dr. Roach, for one second.

In your example the time horizon, I guess, would be long because the situation would be that the utility fails the screen and also needs some sort of long-term commitment for capacity.

Would it be possible that you don't have that situation where they fail the screen but don't have the long-term commitment? Or during the interim period between the time of the failure and the commitment being satisfied through long-term arrangements they still have failed the screen?

You've talked about this long-term commitment and this ultimate addition of capacity to the utility through this competitive process.

How do we deal with the short-term issues that are both prior to that or maybe the sole issue?

Secondly, if the utility's ultimate contract permits them to dispatch the unit, why should the

Commission not pay attention to that power that they would receive at the end of the day over the generation?

MR. ROACH: The same principles can apply to the short term. When you're outside an RTO there's not established a day ahead on spot markets.

I don't mean to exclude the short term. Competitive solicitations can be, should be established for the short term a week ahead, a day ahead, an hourly market.

Again, I think the same five principles apply. I'd to see a collaborative process all the way down through network resource.

I still think for me outside these RTO's I think the nature of the market power problem is still foreclosure.

I'm less concerned about a utility driving prices up to thousands of dollars and withholding capacity. I'm more concerned, even in the short term, about foreclosures. Things like, you know, looking at their plants and saying, "Well, I'm going to compare me to everyone else at $20," but at the end of the month somehow getting a markup on that price.

I'm concerned about high minimum loads, which basically shield a utility power plant and say, "We can't open that up to competition; we can't bring somebody in to displace it."

I still think even in the short run foreclosure is the primary problem.

MR. PERLMAN: I guess I have one more question if I can jump in. There's seems to be a little gap here.

A question for, I guess, the panel. I think Mr. O'Neil's example seems to sort of starkly present the situation where there's an entity that may be looking to buy power at a fair compensatory rate and really doesn't have a lot of options and maybe has no options but one.

Those are the facts as presented. I'm going to assume it as a hypothetical in this situation. If that is the case, what sort of mitigation should the Commission be looking at?

We've talked about a number of things or we've heard a number of things that really said don't go there. But in a stark situation like that where the alternatives are few, how should we consider the mitigation that we would need to impose.

For example, Ms. Alexander spoke negatively about cost of service. What would be an alternative to address that situation? I'd like to hear from anyone who'd like to respond.

MS. ALEXANDER: I just want to kind of contrast the fact that in terms of the up-to rates that I was talking about, I spoke primarily to the spot market.

Bob's example focuses more on long-term supply situations. He wasn't talking about something that didn't have a floor cost as well. Just the kind of contrast concerns about cost-based rates for an hourly, daily, or weekly market.

MR. O'NEIL: Let me clarify two points.

Number one, clearly we do not support the notion of a free-rider. If there's a responsibility of the plant for power supply, prior to the problem you have when you're not the transmission owner is the transmission planning.

If you have a situation where historically you have been served within the footprint of a particular system and what has happened is the interconnections of basically limited size or perhaps reliability purposes -- and then your power supply is terminated and you don't have import capability unless part of the transition of the planning function is to say, okay, fine, if you want to go ahead and terminate cost-based service, what you'll have to do is we have to start planning the transmission system to provide access to outside markets.

You also run into the problem of, even if you build within the system, in this particular case, when Golden Spread went out for its RFP -- and it did go out with an RFP with an independent evaluator and took the extraordinary step of having acquired two plant sites and made those plant sites available to unaffiliated bidders, they said you can bid, you can use our plant sites -- ultimately they wound up with a project that was developed by a third party on one of the plant sites that was owned by Golden Spread.

But at that time we didn't have a problem with the interconnection. One of the things you have to deal now with in terms of bringing the new capacity and plugging it in is are you going to face assertions that you have to pay transmission upgrade costs in terms of participant funding or what have you.

That policy is still evolving. That in itself can be a barrier to entry. Not only can it be a barrier to entry, you have the somewhat ironic situation where as opposed to the customers paying for an investment once, through a transmission charge you may elevate the market-clearing price because now you have internalized the cost of the transmission upgrade into a commodity cost.

And people participating in the market pay multiple times through the elevated market price. So what we face is a situation where you don't have a transmission-planning mechanism in place that takes a look using transmission investment as a means to making the market competitive.

You have a transmission pricing policy and interconnection policy that is suggesting that indeed incremental transmission costs are going to be such that it may again turn you back to your imbedded dominant supplier.

And that supplier is someone who can then go ahead and perhaps add the capability to generate firm power, which is really -- in the real world, folks, that's the market. When you're talking about serving retail load, you can't go back to your customers and say, "By the way, we can serve you hour to hour -- maybe."

They want to flip a light switch and have the lights come on. The embedded supplier with the 4,000 to 5,000 megawatts of generation can add 500 megawatts and perhaps add 500 megawatts of firm power. And any new market entrants in the current regime can't do that.

There are huge obstacles. Again, I come back to the cost-based rates. Until such time as you've got a clear path that has transmission construction arranged in such a way that you can get competitive markets, you have competitive markets.

MR. LARCAMP: I think Ms. Alexander -- one of her points on cost-based rates is it works if you've got a ceiling and a floor. If you need to build the 500 megawatts to serve your load, Bob, how do we assure that the contract length is long enough to make it compensatory?

We don't want you coming in for 10 years and then looking for a better alternative if I'm SPS that's got to finance the capital to do that. Can you address Ms. Alexander's point that cost of service works in that example of long-term product if it is both a ceiling and a floor?

MR. O'NEIL: Absolutely. I'd be happy to. I'll deal with it in two perspectives.

One perspective is the contract that Golden Spread had was a 10-year rolling term, which meant you had a 10-year contract to buy on a cost-based rate, the theory being that if you did serve notice of termination, the customer did, there is 10 years of potential to deal with that in terms of the power supply plant.

Typically that could be handled in the load growth. With the theory of putting your money where your mouth is, the Golden Spread wholesale arrangement with its members basically has them commit to support an investment that's made for their benefit.

But that's a bilateral arrangement where they are getting it at cost. There is no such thing as a free lunch. The commitment has got to be commensurate with the obligation.

MR. LARCAMP: Then you wouldn't object if the incumbent insists upon that same sort of compensatory arrangement with its buyer?

MR. O'NEIL: The incumbent might object.

Remember we've got a long-term contract.

MR. LARCAMP: The rolling 10-year gives you the ability every 10 years to say, "I'm shopping elsewhere."

MR. O'NEIL: Not every 10 years -- on 10 years' notice.

MR. LARCAMP: If I go out and build a plant, presumably I'm recovering that over a 30- or 40-year amortization.

So who takes the regulatory risk? In effect, whoever builds the plant whether it's you or an independent -- or a vertically integrated utility hedges that technology, that fuel source, that cost of capital for the life of the plant in effect.

Who pays for that hedge when people come in on less than life of unit basis?

MR. O'NEIL: Maybe the solution -- one option -- and other utilities have done this. They've had life-of-unit sales contracts, in which case your supply resource is the life of the unit. Your cost obligation is the cost of the unit. And your benefits are the cost characteristics of the unit. That's not necessarily an unreasonable way to go.

MR. HIERONYMUS: Can I jump in for a minute? Two comments.

The first is, this ain't a Christmas tree. We're talking about mitigation of horizontal generation market power. We're not talking about the ability to foreclose competitors from your native load. That's essentially a state problem. We're not talking about solving transmission market power problems based on a finding of generation market power.

My own view is that most of the places where we have market power problems, they arise from transmission. That's been the Commission's view ever since Order 888 and I think the Commission's been right.

Those problems need to be addressed and they need to be remedied. To the extent that this arises from a transmission problem it does need to be addressed.

But what we have here is a contract that allows either party to get out of it in 10 years. Ten years is plenty of time to find alternative sources of supply.

If they are being asked to pay too much for transmission, that should be remedied. But in essence I think what Mr. O'Neil's problem is, is their view is that continuing this contract for a depreciated plant is cheaper than going out and building new supply.

Historically cost-based contracts were regarded, for reasons we are all familiar with, as just and reasonable. The Commission has taken a different point of view. How did that come to be?

Let me remind you of how that came to be. It came to be because embedded cost rates were well above what competitive prices would be. And at that time, when everybody is trying to get their nukes in rate base, all of the customers wanted to be able to run away from cost-based requirement. This is pure opportunism.

The Commission can go back to cost-based rates. Since there are not going to be anymore nukes, so let's go back to the cost-based regime. That's within its purview to do that.

Right now the Commission's policy is market rates. If cost-based rates are below market rates, yes, cost-based rates are confiscatory.

MR. LARCAMP: Do you think that the embedded costs generally are above or below market rates? I'm looking at a remedy for someone that fails the screen. I don't really think it's an effective remedy if costs are above market and the Commission says you failed the screen and our remedy in helping customers is that you get the potential to charge a higher rate.

But I need some help because some have said in California that the embedded cost of the utility-owned generation is still higher and has been on an average basis much higher than the market value.

MR. SIPE: I think in that case you're stuck in not being able to tell an incumbment that they can sell below cost. In a sense we're talking about compelling sales. I don't think you can compel someone to sell below cost. Telling someone they can only sell at cost, even if it's higher than the market -- you would think that would encourage a new entry into the market.

But the remedy is not likely to be that you say you have to sell at what we determine to be the market even if its below your costs. If we assume we're in a position where there isn't that market there to provide that price, in some ways it's a chicken and egg problem.

I understand the conundrum. But I'm not sure we're going to get the chicken to lay the egg to set the market price.

MR. LARCAMP: I think we need to define cost here. The courts have said we can't force the sale below the incremental cost of making the sale. The Coastal case. Are we talking about cost? About a reasonable return on investment?

When Ms. Alexander talks about split savings rates, it was the up-to rate for the unit expected or likely to make the sale so that if we're talking a peaking unit that runs 10 hours a year, how do we allocate the capital cost of carrying a unit that only operates 10 hours a year? In a cost-of-service world someone pays the entire cost of that unit.

MR. SIPE: That's a very helpful clarification because that's what I was getting crossed up with your scenario.

Essentially the way I saw the split-the-savings approach working was actually we're in a world where at least some portion of your capital costs could be made up between the spread between your incremental cost and the decremental costs so that you have some opportunity to make up your capital costs, just as you would being an inframarginal unit in a competitive market. So you're not wholly deprived of capital cost recovery.

When you decide there is no other supplier out there, no other decremental cost to compare it to so we have no inframarginal revenue, I think you have to ask the question, What is your mitigation measure meant to accomplish?

Is the goal to provide the same cost-based recovery that the utility would have gotten under a regulated rate of return somewhere or is it to encourage new entry? Is it to simply protect load from the exercise of market power? I assume it's some mix of all of those, but probably not heavily on the first.

You've got utilities asking for market-based rates. And then I agree with you, Dan, that the solution shouldn't be "We guarantee a market-based rate to recover an embedded-cost rate." I think there's got to be some mix, perhaps some recognition that there should be another decremental offer, some opportunity for capital recovery.

I don't know if it goes all the way to the full embedded-cost rate for the reasons that you've suggested.

MR. PERLMAN: Can I just clarify my question. I didn't mean to get off into Mr. O'Neil's facts. I just thought they were stark in a situation where we are dealing with -- as Don was talking about -- a situation where there's been a market failure.

And we're looking for some sort of remedial response. And it's a very, very difficult element on what we're trying to do. And you guys can really help us because you're thoughtful and have had experience here.

So on a short-term basis, at least in my own view, on a short-term basis the ability to cover all your capital costs if you have a three-hour transaction is not really a very sensible thing.

If you're talking about a long-term structure, all those capital costs come much more into the picture. Plants that are in retail rate base have somebody paying the cost today. Any contribution to fixed cost above that is better than having them lie fallow from a retail rate perspective.

We have to be fair to everybody. We have to recognize that there is a market power problem we're trying to address so while there are all kinds of problems in trying to create mitigation that workable, we're going to be faced with that situation. That's what this panel is about.

And we heard some people take that head on and other people I would characterize as really pointing out the problems with it. I think -- please be helpful to us. I think you're trying to be, but we are really grappling with this.

In addition, I just have a question for Mr. Hieronymus. Do you think, for example, AMP, which limits the ability to capture a price above your reference price -- if you are the clearing unit, is it confiscatory?

MR. HIERONYMUS: No.

MR. PERLMAN: How is that different than the other mitigation that would be related to some camp on what you could charge if it's lower than what a competitive market might produce?

MR. HIERONYMUS: The whole point of AMP and reference prices is to simulate what a competitive price would be. I have various minor problems with AMP, but that's the intent. And it seems to me that ought to be your intent here.

What you're saying in the case of -- I won't say of a screen failure, because I think part of the problem is screen failures -- a lot of screen failures aren't real.

Let's assume there really is a market power issue. What we want under the regime that we're talking about -- that's the Commission's basic policy -- has nothing to do with costs. Short-run marginal costs, long-run marginal costs, embedded costs, costs of entry -- it has to do with markets.

What you want is to make sure that a firm mitigating market power can't sell at more than the competitive price for the product that it's selling. That's why my first best solution is the reference price solution.

If you've got a working competitive market, you look at the price in that market and there are people who propose this, as I'm sure you all know, as transitional mitigation. In Section 203 contexts, okay, it may not exactly be that price. It may be a basis differential against that price.

But I've got a working competitive market. I look at that market. I set prices based on that reversion to say, "This is too hard and I'm just going to revert to cost of service." That one raises all the questions which we're dealing with here as to what in the world that means.

Then it seems to me it's going the wrong place, because what we're really trying to get to is what will the competitive price have been in the absence of market power.

MR. LARCAMP: If you failed the screen and we can't force a sale, why would any seller in an area where they failed the screen agree to sell at a price that is less than cost of service? If the market reference price is below their cost of service, why would they agree to make that sale?

MR. HIERONYMUS: I'm surprised, Dan, that you say can't compel a sale. You have imposed must-offer requirements.

MR. LARCAMP: As conditions for various agreeing to play in certain markets.

MR. HIERONYMUS: Here we're talking about the ability to sell at market-based rates.

MR. LARCAMP: Right.

MR. HIERONYMUS: I'm not sure that motivates a full-scale must-offer requirement, particularly, since as I said earlier, most of the customers that will be outside of the area, where supposedly market power exists.

But, you know, let me throw my question back at you, which is if they really have that market power, why would they limit what they wanted from the market?

The full cost of service?

The point is if they really have market power, you're going to have to limit what they can get somehow. My only point was, the cost of service is essentially an irrelevant number for deciding what that limit ought to be.

MR. O'NEIL: Dan, could I make a comment? Again, I question whether you could compel someone to sell below cost. I think that would be really shaky legal grounds to impose an obligation that someone sell below cost. So we are really talking about whether you're selling at cost or above cost.

And if someone has market power, then the question is why in the world would they sell at cost if they can sell cost? And by cost I mean including a J and R return.

The question of what happens in terms of a peaker that you use a couple of hours a year, I remember -- God, it must have been four years ago -- sitting with you and some of the staff and seeing that a price cap didn't necessarily make sense for peaking capacity because the cost of a megawatt hour of peak capacity -- if you buy for a year, it could be $54,000 a megawatt hour for that one last megawatt hour.

Dr. Hieronymus mischaracterized what I was saying. I was not here arguing that an existing contract be perpetuated to the extent that it's terminated. If it's gone through the term, so be it. As a matter of fact, Golden Spread is going about purchasing and installing additional generation. The issue here is, if a FERC-regulated utility -- and that would include Golden Spread -- has market power. It's got market power. For this panel's purposes that is assumed.

Why is not the pricing above cost evidence of the exercise of that market power?

MR. O'NEILL: It's because the market changes from time to time. And sometimes you're not recovering your average price that is calculated by the cost-of-service rate. And at other times that's why cost of service at its best works for life-of-unit contracts. And after that it's pretty shabby.

MR. SIPE: I think that a lot of the comments are sort of focusing on what I think is the fundamental soundness of the split-the-savings methodology. Essentially cost of service in the sense of something beyond what your incremental costs are for production is probably not a relevant number for this inquiry for the same reasons I think the order itself recognized they weren't relevant.

The issue in a competitive market is, if you're working as an inframarginal unit, no one should be looking over your shoulder whether you're recovering more than your cost of service, less than your cost of service. That's what competition does.

So the sort of cost of service idea, as you point out, doesn't have relevance when we're talking about what should be either a mitigation to get us back to where we would get if we were in a competitive market, or address what the competitive would produce.

I think the split-the-savings methodology at least theoretically should wind up close to what the results of a competitive market would be if you had a huge spread between your incremental costs and the last decremental unit.

You can make all sorts of money and nobody looks over your shoulder and says you can't recover all your costs. But there isn't an institutionalized attempt to get at your cost of service and to sort of state how much you're going to recover.

The one place where it breaks down, I think, is where you absolutely have no decremental bid that you can compare it to. That one I think needs some further thought.

MR. O'NEILL: We've given that further thought and that's one of the question I had for you. You said something very quickly and I didn't fully catch it. You said scarcity pricing and market failures don't go together.

MR. SIPE: Yes.

MR. O'NEILL: This is an example of where their last incremental unit is being dispatched. You are now starting to short reserves, okay, to serve load. And you're not seeing any price for the fact that you're shorting reserves.

Now, in New England and in New York they have basically put in mechanisms that say as soon as you start shorting reserves, we're going to show you a scarcity price.

That scarcity price is there basically to deal with the market failure, where the consumers aren't bidding in. The customers are not bidding in and they are not telling you what they are willing to buy at so you can't get an accurate price. And I thought you said that wasn't good.

MR. SIPE: No. You're talking about essentially a capped price.

MR. O'NEILL: Not necessarily.

MR. SIPE: I would talk about a capped price. Or I think what I said was you are profiteering in necessities.

What I said is, where you get to the point where there is no discipline on the upside of the market and you have either a requirement that you have to buy, or in the alternative, no sufficient demand response, then there is no market mechanism to set the price.

You either have to have an imposed cap, which bears some relation to a goal that you're trying to achieve other than inducing long-term demand response -- but it cannot be said that by a market in any but an arbitrary fashion, which is how high can the numbers go in your software.

MR. O'NEILL: We already said load margins. In somewhat of an arbitrary way we calculate loss of load margins. We do a whole bunch of simulations. That's all administratively set. Should we abandon that too?

MR. SIPE: You're mistaking the use of the word "arbitrary" with "thoughtless."

(Laughter.)

MR. SIPE: I do not think you've set them in an arbitrary way. I disagree with you.

MR. O'NEILL: We're not asking for thoughtless scarcity pricing. We're asking for thoughtful scarcity pricing.

MR. SIPE: Then we're both asking for the same thing. And you agree with me.

(Laughter.)

MR. SIPE: Because thoughtless scarcity pricing is simply allowing the market to somehow magically set a number. I think actually capacity margins and reserved margins are not set arbitrarily. They are set much as an art rather than a science, but that isn't arbitrary. That is a matter of taking in as much information you can get and making a reasoned decision based on policy goals of where you think things ought to be. I think that's where your price caps are.

MR. O'NEILL: We're doing the same thing, scarcity pricing, aren't we?

MR. SIPE: Scarcity pricing as defined by just let the market go where it will.

MR. O'NEILL: That's not scarcity pricing. How about scarcity pricing in New York and New England?

MR. SIPE: I think those reasonable exercises that I think is not scarcity pricing as an economist would understand it in the sense of simply let the market set the price. And when people can't find more, they'll quit. They'll turn off their lights.

When you have that disconnect, you have to have some arbitrarily set numbers somewhere. That's based on a policy goal, which is not just a market-driven number. It's got to be thought out in some way.

MR. PERLMAN: Can I ask you a local question, Bob, because I know Bill and Craig have something to say. How do you deal in your split savings approach with the issues that the two Bills raised with respect to, let's say, I'm a marketer?

I don't have any decremental cost. I want to buy at the bus bar and I'll immediately mark it up to market and take advantage of sort of an artificially depressed price that I get to buy at. And there's no restriction on what I can do because I have market-based rates in that situation.

And I think a lot of the buyers may be in that type of characteristic business model. Are you going to preclude them from buying? Are you going to direct this power until only people that have decremental costs -- how are you going to work that aspect? If that situation --

MR. SIPE: Most of my comments were focused on sort of the theoretical validity. If you have a decremental cost, I think one of the things that supplier is going to run into is all the people he wants to sell to can also buy that power.

You're positing a situation where somehow this guy that wants to buy this power at this incremental cost is going to sell to someone else, who he can somehow get the power to that these people can't themselves buy at that incremental cost.

I'm not sure; I suppose that could happen. But in an efficient market you should probably be getting bids from other folks who want to buy that power at incremental cost.

If you have people putting in bids, simply bids for power that are matched up and someone simply meets their bid, that might be the way to solve it. Post the incremental price and you take the highest bidder.

But the idea is to make that power available. And again, if you've got a decremental bid -- and we're not talking about a scarcity situation. We're talking simply, this is the last piece of incremental power, in which case I think we've got to go back to some administrative cap.

But that would seem to be a reasonable approach, a tweak to solve that problem. Or you don't have a stated decremental cost.

MR. ROACH: Just real quick. There's a tendency here that we've got to watch. I just leaned over to Bob and I said, "Bob, you don't want to buy in the spot market, do you? You have a long-term need."

What we've just all been talking about are remedies for the spot market. He has, as I understand it, an expiring contract and wants to replace it. At that point we don't have to immediately start thinking about short-term markets and mitigation. We can do something that's really important and totally with not retreating to cost-based rates.

We can begin to accommodate competition. We can do things -- again, if I heard Bob right, one of the major impediments in getting competitors to serve his load is the transmission at work. It's to me a network resource issue.

The Commission can certainly do something about a local utility that fails the screen and telling them what to do about giving timely, accurate estimates of what it takes to deliver power, what it takes to be a network resource for him.

If we have a longer term market, we can do things. We have the option of not going back to cost-based rates. We can accommodate competition. We can accommodate and really create competitors. We can do it primarily through transmission.

But if we have enough time we could actually have people build new segments. I'd like that.

MR. O'NEILL: On the issue of timely and accurate estimates from the utility, our track record hasn't really been good on that. We certainly demanded that. But the utilities' track record is not really good at timely and accurate estimates.

What would you propose we do to get timely, accurate estimates?

MR. ROACH: All within the context of the solicitation -- and I mean that -- why is it that they can't give you an estimate?

I've seen lots of affiliates pop up with network resources. No one even knew that they had that status. I think the studies -- I understand that it might not be the final number, but it's got to be a good-faith number.

I think it's got to be done in the time of the solicitation. If that's four months, four months; they've got to do it.

MR. O'NEILL: What do we do if that doesn't happen the way you would like it to happen?

MR. ROACH: You know, I don't have an answer for you. It's got to be some sort of penalty. It could be a financial penalty. It could be designation as a network resource and tell the utility to redispatch to create it -- those sorts of things.

MR. O'NEILL: We've told them that. It's part of 888.

MR. LARCAMP: Do we give settlers the choice of living in one world or the other, but not living in both?

MR. ROACH: Whether the world's network resource or not?

MR. LARCAMP: Cost of service or market. If you want to be in the market world, then you do certain things like you've suggested on your five points. But if you don't want to do that, then there is a default world and that world --

I think part of the problem is that we allow sellers to move in and out. Those that are concerned about their cheap cost-based power escaping to other regions, you know. They want to play cost of service for everything. Is that an option?

MR. ROACH: If you're asking me my druthers, I really feel strongly that we want to move beyond cost-based rates. The essence of competitive reform is to get to price. Once we get to price, in my view there becomes a true incentive for innovation.

Without it, if you just have cost plus, you just don't have that incentive for innovation. It's really old world. I'd to move as rapidly as we could away from any cost plus rate.

On top of that, I just don't think it's a good deal for the consumer. I think it's too much risk for them. I'm not talking about today all of a sudden nobody has any cost plus rates. Certainly there's going to be a lot of capacity.

Dan, addressing your issue of states that are concerned about it going to other markets. We're going to have a long legacy of cost plus rates. But in cases where we're going for new competition, I'd much, much prefer to take action to create robust competition, accommodate robust competition rather than go back to cost.

MR. LARCAMP: Just to be clear, my example was only in the wholesale market.

MR. ROACH: Yes.

MR. O'NEIL: In terms of identifying markets, in terms of long term, short term, it could very well be that a market proxy price is appropriate if you have sort of a short-term aberration where someone wakes up one morning and they've got a little bit of market power and, you know, they fail the test, because then that's an aberration in what is otherwise a functioning market.

The question is, what happens -- and it's not so much maybe a failure of the market. What happens if a market just hasn't developed? It's just not there yet. How do we go about getting it there? What steps do we take to encourage the development of the market? Transmission is a big part of it clearly. But for purposes of this particular panel, we did have an issue saying you can short-term pricing contribute towards some long-term stability and what have you.

So I think it's relevant to look at the long-term for purposes of this panel. But I think you're going to have to look at a whole more than just short-term pricing.

You are going to have to look at the transmission.

MR. O'NEILL: I don't think anybody was saying we're not paying any attention to the long term. The ideal is if you have transmission access and the ability to reach for alternative suppliers, the long term takes care of itself.

The question is, how long valid is that assumption? That's an important validation question.

MR. O'NEIL: When Golden Spread was taking over 14 megawatts, the basic power flows are not going to change that much. The base case models are wrong. It turned out there was a big problem in another state.

MR. O'NEILL: Fourteen megawatts?

MR. O'NEIL: Fourteen megawatts. When you talk about in the real world where the rubber meets the road, there's a lot of chance to become road kill if you're not careful.

(Laughter.)

MR. RODGERS: If I could jump in here. Some of the folks on this side of the panel have talked about the need to look beyond just short-term mitigation to long-term mitigation.

That actually ties in with a point that I think Bill Dudley made in his comments. I'm going to read a quote from page 2 of your comments. And Mr. Dudley, you said, "Commission's staff's underlying assumption about spot market pricing tempering long-term or forward pricing is not necessarily correct."

Does that suggest in your mind that staff's mitigation or the Commission's mitigation should look beyond just doing short-term and also encompassed long-term mitigation?

MR. DUDLEY: No. First of all let me mention there's been a lot to sort of respond to here and at some point I want to go back to Dave Perlman's original hypothetical, because SPS at least has a different view of the hypothetical than maybe Mr. O'Neil does.

But to your question, the only point we were trying to make there is that what we were -- again, there's sort of this assumption in the staff's analysis, which I think was actually maybe in the original in the original order, which sort of says, okay, we'll mitigate spot market prices.

That will sort of keep us honest in the long-term prices. If long-term prices come down, people will buy in the long-term prices and will rely less on the spot market prices. I think that's somewhat convoluted reasoning.

The only thing I was really trying to make the point on is people access or utilities access or sell into the economy energy markets all the time. They now pretty well have an idea on a day ahead basis, you know, what their access is.

They know what their fuel prices are going to be. They know what they can sell it at and not take a loss or anything.

When you start to get into the long-range market there reason there's sort of a disconnect there is that sort of different factors come into play. You have problems projecting what your costs are going to be. There's more hesitancy to sort of sell forward.

We are operating some systems that are tight a lot of the year. There's sort of more hesitancy to sort of make a forward sale with a lot of the uncertainties. So that's all I was trying to suggest -- that there is a little bit of a break in your thinking there. Just because of the way at least we access the system. We look at the spot market, I believe, a little bit differently than we look at forward sales.

MR. RODGERS: If one fails a market power screen, do you think there are long-term concerns that the Commission should have and should try to mitigate?

MR. DUDLEY: This might be a good point to sort of jump in to the long term. But I think the area of primarily concern ought to be in the daily markets. We think your approach is right -- to focus on the spot market.

When we mean spot market, we're talking about basically daily or day ahead -- going to immediate delivery, particularly the peak hours of those days, because even there you're basically breaking out the power that you're selling in the peak periods and nonpeak periods.

So we think you have the right focus. The focus ought to be on the spot market and in particular on the peak hours of the day.

This might actually be a good point to jump back to David Perlman's hypothetical about sort of the true, sort of long-term transactions, because I guess we have a quite different view of the Golden Spread situation.

The thing to remember about Golden Spread was that they were at one time a full requirements customer of SPS and they could have remained so.

I was interested to hear from Bob about the life-of-unit term contracts because the one that originally changed that contract from a full requirements customer to a partial requirements customer was basically at Golden Spread's behest. They wanted to make a power plant.

We're heard today that the underlying concern of that was some concern about regulatory failure. I'm not sure I'd heard that one before. That's not to say that wasn't a concern.

But the main point here is that when you go from being a full requirements customer to being a partial requirements customer, you then obviously have an obligation to plan your system a little bit more carefully.

In the particular case of Golden Spread you have your unit. You have to plan for contingencies related to that unit, which we actually believe Golden Spread has done fairly well with us.

For example, we have a replacement energy arrangement with them, which is a reciprocal agreement, where we both have obligated each other to sell excess in times of sort of emergency or need.

They sell to less on that same basis and we sell to them. The point is, once you go to partial requirements, you then do have to sort of monitor this a little bit more carefully.

And in this case Bob has mentioned that we've given notice. Yes, we've given 10 years' notice. At least in our view of the world we are a system that has found ourself capacity-tight in many instances on a lot shorter notice than that.

And we added capacity through long-term purchases from IPP, from new projects -- mostly from new projects. We added, I think, around 2,000 megawatts in the West, for example, in Colorado, on a lot less of a timeframe than 10 years.

So should the Commission be worried about sort of market power 10 years out? I would suggest that there's actually plenty of opportunity there. There's plenty of options there that aren't present necessarily in the short-term markets. There's plenty of opportunities.

So when I'm hearing this argument, I'm not only worried about, I guess, free-riding, but I'm also sort of worried that Bob is sort of wanting it both ways, because it seems like they want the ability -- Golden Spread wants the ability to go out and shop and get lower priced resources and plan its system the same way.

But at the same time I'm hearing, well, there's concerns that we might not be able to arrange things. And you should want to sell to us at cost-based rates.

Well, wait a second. We're getting in both ways in that situation because we can't necessarily plan to have them on our system at that time while they're out shopping around. It really sort of puts us in an impossible position here. I'm not really quite sure that the hypothetical was totally valid.

One other thing I wanted to mention was in response to Dan Larcamp. And I guess others, too, have been talking about cost of service.

What I'm hearing is we're sort of conflating things. Cost of service sort of means a couple of things.

If you're talking about energy sales in the spot market, cost of service -- arguably cost of service is incremental. But as we've suggested the Commission has always allowed an adder to economy energy sales to allow for utilities to capture some of the value of the capacity benefit.

So you're talking about the low cost rates. If you're talking about sort of below fully allocated cost-of-service rates, those happen all the time in the economy market. I would suggest that they will continue to happen all the time in the economy market. It's just the way the economy market is.

On the other hand there are going to be periods of scarcity as we saw in the West. And during those opportunities maybe we get a rate that's above what would be sort of a fully allocated year-round cost of service.

On the other hand, that's not necessarily a wrong approach, because it gives us an opportunity to give a real contribution to our fixed costs and have a capacity available that serves the market in these times of scarcity.

MR. LARCAMP: Coming back to -- I think, Bill suggested perhaps a regional rate mechanism as a default, which seems to me to have the benefit of providing some incentive for a long-term infrastructure development at the same time you are trying to mitigate a screen failure.

And I'm drawn back to sort the old area wide rates again. But how does staff in a way -- I mean, we're frankly not interested in spending 24 hours a day trying to determine what the regional competitive market price is.

But how might we craft that type of default, which, as I understand it, basically says, let's assume that we administratively can determine what a competitive rate would be in a region. And if you flunk the screen, that's all you get because that's all you'd get if competition was applicable.

MR. DUDLEY: I guess what I was thinking of, it would almost be sort of an up-to rate applied on a region-wide basis. I think if I remember correctly, with WSPP that was sort of the original WSPP. As you know, it was sort of the first experimental market-based sort of market.

MR. LARCAMP: I don't think were interested on staff of giving you the weighted average of the most expensive unit. That doesn't look to me like a very competitive solution after what we've learned since WSPP started.

MR. DUDLEY: My suggestion is you could tinker with it a bit and come up with something that's sort of above -- certainly above incremental costs, certainly above share the savings.

But it gives sort of a real contribution to fixed costs of the units that are being relied upon to make the sales and also avoid the free-riding problem that we think the share-the-savings approach will foster.

MR. RODGERS: Can I ask clarification on that? Would that up-to rate, then, be higher than the rate that the entity that we found to have market power was charging as a prevailing price in the market at that time?

MR. DUDLEY: It could be higher or it could be lower. The point of the up-to rate is market forces are driving it down. On the other hand, if it's a period where there is some scarcity, the up-to rate will probably be a lot less than what we could otherwise charge on the market.

MR. RODGERS: I had a couple other questions if I could.

Mr. Dudley, you said the Commission does not believe that the screen should not be applied on a monthly basis. The period of greatest concern should be what might occur in peak periods when supply is tight. Off-tight, when supply is more plentiful, should not be of this great a concern.

We heard yesterday from several panelists, including the gentleman from the FTC, that we would get a more accurate picture of market power if we used different screens, if we looked at different periods, including off-peak periods.

Can you explain why you think those viewpoints were incorrect?

MR. DUDLEY: First of all, I don't know what the specific comments were. I can sort of maybe illustrate what the concern that we have is, which is this:

If you have a utility which has a pronounced sort of spike peak, which one of our utilities does, the concern would be that somehow you might be able to pass in the on-peak hour, which as we say we think is sort of the greatest concern. And at that time it's passing, undoubtedly because there's a certain amount of megawatts out on the market.

Just for the sake of argument, let's just say 1,000. So on an absolute basis there's 1,000 megawatts of capacity or energy that can be out there as an alternative to purchases or sales by us. You go into an off-peak period. All of a sudden we're out of peak. All of a sudden we have excess resources.

Our threshold goes way up at the same time that 1,000 megawatts is still there. Even though our threshold goes way up out of peak, does that really mean we're a problem? We still have that 1,000 megawatts that's still out there to compete with you.

That was sort of a concern that we had. That's what led to the comments.

MR. RODGERS: You also said in your comments that you thought in doing the calculation the Commission should not attribute the applicant's installed capacity that's used to serve native load.

MR. DUDLEY: A lot of people have said that. But yes.

MR. RODGERS: You also said periods off-peak when supply is more plentiful should not be as great a concern. But isn't that the very time when the applicant's capacity that other times is used to serve native load is available for sales in the wholesale market for off-system sales?

MR. DUDLEY: I think I missed something in that. I'm sorry.

MR. RODGERS: What I'm saying is that during the off-peak periods, that's when the IOU has capacity that at other times at peak it uses to sell for native load to provide native load service. It has that capacity available for sales off system at competitive prices. So I'm just wondering if there's a little bit of a disconnect between you're feeling on the one hand that native load should be taken off the table for that hypothetical IOU, but on the other hand we shouldn't be concerned about off peak.

MR. DUDLEY: That shows a disconnect because I guess the way I was looking at it is that the peak period is sort of going to be typically -- it's representative of what's happening in the region as a whole.

At that point we don't have a market power problem. Somehow we pass the screen in the peak period. Then it seems to me things should be okay. Off peak shouldn't be as great a concern. Again, if we pass through in the off peak, it means that the resources available in the region enable us to pass.

Maybe it's a simplified assumption, but the point we were trying to make is, if we go into the nonpeak periods, it's likely that same amount of capacity and resources, competing resources, are going to be available. That was the point we were trying to make.

MR. LARCAMP: What do we do, regardless of the peak, off peak -- I sort of think afternoon and evening, the middle of the night. We've had some experience lately where reserve margins have become very, very tight in shoulder months before we hit the peak season.

Is that a legitimate examination? I mean, candidly a concern of some of the independents is that the vertically integrated utility controls the maintenance scheduling for when you do take your plants on and off for maintenance.

Is it relevant for us to look at sort of summer peak, winter peak, and shoulder months to basically see what capacity is available by whom in those periods even though they don't fall within the traditional definition?

We've seen in the West and elsewhere some very, very close calls in sort of May, for example, when it gets real hot unexpectedly and a lot of plants are down for maintenance. Should we be concerned about what's available to sell in those periods?

MR. DUDLEY: First, one clarification. Then I probably ought to punt to the experts on that.

But when I was talking about peak, I guess I was talking about not only sort of daily, nightly, but I was in fact referring to sort our system peak.

In the case of our utilities, they are actually fairly different on that. For example, one of our system companies has a very pronounced summer peak. One of the utilities -- I believe it's still summer peaking, but it has a winter peak that's very close. So yes, I think you can look at those in terms of the shoulder months and the maintenance and all that.

I really can't say that I've thought that through. And I'm not sure I really should hazard a guess on that. Perhaps that might be when you want to kick to Mr. Hieronymus here.

MR. HIERONYMUS: Let me take a try at it. It certainly used to be a real problem, a predictable problem, when you had 120-day nuclear refueling outages in places like New England and Colorado that are duel peaking.

I suspect it's less today. And when you get the shoulder month problems, it's because you get an unanticipated load. You've either spread the maintenance out too far out into May -- and you do sometimes get hot days in May -- or you've got plant that's on reserve shut down. It's not actually on maintenance and it's not available.

I think it is a potential problem. I also think frankly that any test that's based on standard maintenance assumptions and standard weather, i.e., load assumptions, is probably going to miss it.

More generally -- and I think you've triggered something that's real -- but more generally if you look at this off-peak, on-peak issue, off-peak -- Bill keeps saying the other capacity is still going to be there.

Well, it's more than that. Because other people's load is down, there's going to be a lot more capacity. And the wholesale accessible load itself would be down, because it's off peak.

So it will be a lot more capacity chasing less load. That's the reason why it's reasonable to expect that if you're going to have a problem on peak, you're going to have a problem off peak.

I don't personally have a problem if the Commission were to say prove this to us. Let's put in off-peak tests for a while and see and if it turns out that people don't fail it, then we'll take something out of Hieronymus's rice bowl and say, "You don't have to file that anymore."

MR. PERLMAN: Can I follow up on something I think you had suggested earlier?

Dr. Hieronymus, it seems like it's something that might be workable -- as I understand it, to pick a liquid trading location that had price transparency and had enough liquidity for us to conclude it was a competitive price, then attach a basis to that that would somehow be determined.

I guess it would have to be minimum day ahead so people could transact at or below that number, then have that be -- in the face of the screen failure and the need to mitigate -- be the competitively based price that would then be the mitigated outcome.

That you couldn't charge above that -- is that something that has appeal to anyone else on the panel? Or are there problems with making it work? And did I understand correctly?

MR. HIERONYMUS: You did see it. And there are real problems with doing that. I alluded to the fact that there aren't very many available reference buses.

You brought up the timing issue. It doesn't do much good to find out that yesterday the day-ahead price into energy was what it was from the point of view of doing transactions.

If you try to expand the thing, you get an even bigger timing problem because it may be that the only way you can get a price pertinent to Colorado, for example, is that the Commission collects transaction data and basically creates a price.

You already had your data collection problems. So there are real implementation problems with it. There are, however, areas where this is available. And so at least where it can be done, it seems to me that this is a very promising avenue for mitigation.

If I can take this opportunity to go back to something Dan brought up, which is the area-wide rate making. Despite my reservations about it, if you go that way, that's a key where the staff idea that was alluded to in your paper of some sort of longer term revenue cap rather than an average hourly price cap makes a lot of sense.

It's terribly important that you not get a rate that says, well, on average this is, we think, a reasonable IE, sort of like a competitive price, when as Bill Dudley has said most of the time the market will clear below that. And some of the time the market will clear way above that.

Since it's merely a price offer rather than a put, that means most of the time you get an up-to rate, which is less and the time that you ought to be making it back, you can't.

The only way you can have something like that in my view is if you said -- and, of course, this raises the question, well, what happens if you're overcollecting? You have to find some way to give the money to somebody.

But what we're going to say is you are limited in terms of what you can give to X over the course of the year or whatever. But you can get it whenever you want.

MR. DUDLEY: Another way to look at this is, there's a lot of valleys and there's the occasional peak. So what happens with the price caps, of course, is that you shave the peaks so you get a lot of valleys.

If you're looking at it from an overall total cost of service perspective, even when we get the occasional prices above a peak, you can't say that we necessarily are overcollecting or anything.

MR. HIERONYMUS: Dave Perlman asked whether anybody had any comment. But I'd be interested in that too. MS. ALEXANDER: I agree there's a problem finding the right index price, if you will. We get too far away from PJM in the Northeast markets. You don't have any numbers you can use.

It seems to me we've spent a lot of time talking about how to cap prices today. It's about all we've talked about. I'm just wondering if you asked a little while ago, David, about whether other ideas you had about how you could address these problems.

And one of the things that was floated out in the paper, which I think is a good idea, is to think about letting applicants propose mitigation measures. I also think that you're going to do a gross screen of capacity numbers and you're going to see a problem. It's going to screen a potential problem to go out and price cap for a season or a year because of that number.

If you're going to bring out the elephant gun, you'd better have an elephant in your sites. And I'm not sure that that screen is going to give you that information. What you can do when you have somebody that fails the screen is you do a closer analysis, you find out exactly what the problem is. You start thinking about what solutions are that will change the competitiveness of the market, not just let market power coexist in that market with mitigated prices.

You put the burden on the applicant to come forward and say how can you do something to make this market better, more competitive? What can you offer? What will directly attack the problem that we see once we look at it more closely, it might be an off-peak problem. It might be a problem that only occurs during certain periods and it might only occur with respect to certain customers.

And there might be creative solutions out there that people can bring here that would really address the underlying problems: How do you get to a better, more competitive market? How do you get rid of market power rather than how do you mitigate it?

So I thought that was the best idea in the paper -- was let the applicants come forward with some ideas.

MR. PEDERSON: We've heard a lot of panelists yesterday build up to the same suggestion. If a utility is found to have market power, have them come in and propose mitigation. We've heard some of that today.

But from a regulatory certainty perspective, don't we really need to have a default mitigation measure out there as a backstop? This is what's going to be imposed and then let the mitigated themselves come in and propose something different.

MS. ALEXANDER: I remember saying that when I was here.

(Laughter.)

MR. LARCAMP: She no longer processes 60-day filings, Jerry.

(Laughter.)

MS. ALEXANDER: I understand your 60-day filing problem. That's really a problem, which you have, I think, with new applicants. They have to get up and running. Most of your new applicants are new entrants to the market.

I'm thinking -- more likely than not I think the 74 that you have sitting on the shelf -- I try any reports, so I'm not sure that you have the same type of time constraints. You could require people to come in with some lead time and come in with a proposal that they would execute or well proposed to execute. Maybe some transitional measures if you thought it was important to do so.

The other thing. It seems to me if somebody comes in in a trending report the market shares don't right -- you're not working for a vacuum. Those market shares were there yesterday. You can see whether the market was working well or not.

You have a lot more places to get information when you're dealing with a known entity in a known market structure. So I'm not sure you'll always be in the same time crunch.

MR. PEDERSON: My concern was a little broader than that. I think we've heard from different financial institutions that price certainty is important. Regulatory certainty is important. My concern was more along those lines.

If the Commission were to go out and say, well, this particular seller has market power, but we don't have a default mitigation in place, all we're saying is we found that you have market power and I'll come in and we have to talk about it.

Is that going to give enough certainty? Not to put up regulatory barriers to entry? That's kind of where I was going with that.

MR. DUDLEY: Actually I could weigh in on this one. This may be one where we sort of differ from many of our colleagues in the industry.

But having been a FERC practitioner here for many, many years and knowing the way things sort of happen in one proceeding and then end up becoming policy for the entire industry, we at least -- the pragmatic approach. Would I think like it if a default backstop mechanism came out of this proceeding? **

That's not to say that other people can't propose something else in other contexts. Who knows? We may even be one of them.

But it would seem to be a wasted opportunity if the Commission in this proceeding did not come up with something -- hopefully good.

MR. RODGERS: Chairman Wood, did you have some questions?

CHAIRMAN WOOD: Mr. Sipe, you referred to a provision in the order that actually at the time I thought was the heart of the order. Maybe I got kind of distracted by the SMA screen.

But I'd like you to flush out for me your cursory comments in your intro remarks about the requirement that was suspended, but which will unsuspend eventually and which requires the transmission provider, when they perform the study pursuant to the interconnection request, to treat a proposed generator or proposed transmission service applicant in a certain way.

I'm going to ask you two questions. Translate into English why that's important to you as a customer. And then to -- did our order 2003 interconnection rule do anything to help, hurt, or is it just neutral as to this?

MR. SIPE: I think the major reason why it is important to the end-use community generally is that free entry into the system and competition on the basis of the transmission capability of the system as it exists seems to us to be simply the standard for a competitive market, competitive entry.

The standards which have been applied for deliverability are essentially economic preferences masquerading in engineering mythology, mostly from our point of view.

If you can interconnect to the system in a way that preserves stability, preserves reliability, and preserves the transfer capability of the grid and you are electrically situated the same as any other network resource in those respects, then you have not harmed the transfer capability.

If you could deliver energy to the grid, you can deliver capacity if you're chosen. We believe there's got to be that sort of open entry. People have got to want to use the highway and they shouldn't be forced to build their own highway before they can compete.

We can get into the details through questions or anything else as to how I believe that standard fulfills those requirements. But that is the essential sort of bottom line reason why consumers believe that's an absolutely essential ingredient in the competitive market.

Order 2003 I think was addressed to a variety of situations and depending upon how it is applied in practice, may complicate that situation and make us fall short of that standard or may in fact allow us to achieve that standard.

If you are in a situation where surplus capacity is not going to be permitted to come out of the system because your least cost resource planning doesn't allow you to essentially build surplus competitive capacity, then I think the higher interconnection standard that is in the NOPR will at least allow a unit to get on and build what I believe is redundant transmission capacity -- at least enough transmission capacity to pretend its not serving load that's currently being served and it should in somewhere else.

I believe that higher standard has limited usefulness because it contains those types of assumptions unless the displacement, which is allowed under it, is a true one-for-one displacement.

I think the bifurcation of those standards calling one energy and one network resource has done a little bit of disservice to what I understand an energy interconnection ought to be, which is in fact the unit that's capable of providing or delivering energy to the grid.

It makes it sound like a network resource interconnection or some animal that had some greater ability to deliver something to the grid. You know, capacity is just energy over time.

But I think the Commission needs to pay close attention to how those standards are applied in actual practice and whether displacement is allowed and whether there is a regime within the state that allows the utility to use its control of what it considers the deliverability standard to essentially say, "Our native load is off limits for wholesale competition," which is essentially what I believe is incorporated into some of those standards as I've seen them formulated.

CHAIRMAN WOOD: Thanks. Actually I misspoke. That provision was not stayed in the December 20th order.

A question just broadly for the panel. Back to the mitigation. If a form of cost-based rates were applied to those that were found to generate market power, which I think some of you have pointed out why we shouldn't do that, but if we pile forward nonetheless, what impacts could that have on investment in new generation?

Let me just put in another "if." Does your answer change if it's clear that new unaffiliated entrants that don't pass -- or, excuse me, that don't fail a screen have unqualified market-based rate authority?

MR. HIERONYMUS: Let me try this first. The question ultimately is an empirical one. Dan asked a while earlier whether market rates were higher or lower than embedded cost of service at the moment because of gluts in some areas competitive rates clearly are lower. In other areas they are closer.

But I think everywhere today market rates are below the cost of entry. And entry is not happening, shouldn't be happening with the exception of a few pockets that we're all aware of and there it can't happen, which is why there are still pockets.

But if we get back better into balance to where you actually would like to see entry and you start clipping peaks because you can tell sales at embedded cost of what are by then fairly well depreciated resources -- to the extent you successfully clip the peaks you are going to have prices that won't support entry when you need it.

That's my expectation.

CHAIRMAN WOOD: Is that true? Even though the people who are clipped are well to the left end of the dispatch curve so the 60 percent that may be represented by the market share of the mitigated company as you're starting -- once you get back their clipped prices, you're into unmitigated territory with people who are basically seeking where the market goes. Don't they, in fact, with their own mitigated price, set the price of entry for the new investor?

MR. HIERONYMUS: They could. But, Mr. Chairman, you seem to be thinking about this as if this were a bid cap, not a price cap. It may well be. And I don't know how one would allocate this below market energy -- who decides who gets to get it and on what basis. But some people who would have been paying the market price are paying considerably less.

Your point's a good one. If there's enough people out there who are paying the market price and it's high enough to support entry, that will attract entry, yes.

CHAIRMAN WOOD: Thanks.

MR. RODGERS: As was the case yesterday with both panels. We had an opportunity for those in the audience to come forward and ask questions. I'd like to make that opportunity available for those in the audience today.

If you're interested, please come to one of the microphones down at the end of either of the side aisles.

MR. LARCAMP: Bob, before we get people down here, do you have something?

MR. O'NEIL: The one concern I had in terms of Dr. Hieronymus's observation is that if you have an entity that has a market power -- that's the assumption -- which probably means they have some surplus capacity.

I'm trying to understand why it is that somehow they would insist upon a price high enough that would permit new markets to enter -- or rather, new entrants to the market. I would think what you'd normally do is you'd price it just low enough to keep the new entrants out.

In economics 101 -- then again, I'm not an economist. Maybe I missed a class.

MR. HIERONYMUS: You don not necessarily want to keep out entry. There's this great myth that all utilities want to keep all their native load customers and that they want to build all the new capacity. And that's true of some of them, but not all of them.

Your systems grow. It isn't lucky if entry comes in and I don't get to sell what I've got. It may well be that the utility is perfectly happy to have entry come in. I know of a lot of utilities that indeed do foster entry.

It's not that they are necessarily opposed to entry merely because they have a generation fleet of their own. In some cases you're undoubtedly right.

MR. DUDLEY: We're a case in point in that, as I mentioned before. I was looking back through some pleadings or comments I filed elsewhere and I saw one figure that I think is sort of telling. It was given a couple of years ago, but we pointed out to the Commission that in the WSCC we had contracted for 1,800 megawatts of new generation all third parties -- all supply contracts from third parties.

So it wasn't like we had a big capacity meter and it wasn't like we were going to put iron in the ground ourselves. There's a lot of regulatory push in that direction, too, from the state commissions.

If we want to build anything, we have a pretty burden to justify why we can do it better than the Calpines of the world or others out there.

So I just wanted to point that out in sort of support of what Bill was saying.

MR. ROACH: Two real quick comments on the Chairman's questions.

Taking them in reverse order, first, you are right, Pat. The concern with any price cap is that it stifles new entry and we just get into a shortage problem. So I definitely share that concern.

Secondly, we would presume as you stated, that anyone who does not fail the screen is not so mitigated, is not capped.

Then I do agree with Bill that at that point you now, then, have a market price perhaps here and you have one chunk of power from the mitigated supplier at a lower price. The question is, who gets that? So we have that kind of duel price market. But you are right on the money. The major concern is stifling new investment.

Then I wanted to go back to your question about network resource. I wanted to agree -- I think I heard you say that of the mitigations proposed here, you thought that help on getting network resource studies was -- I think you said it was the heart of the mitigation.

I think it is. That addresses head on a very important impediment to competitive reform in short-term markets as well as long-term markets.

I just wanted to agree that that is a big deal.

MR. HIERONYMUS: Can I just throw in something gratuitous? And this isn't for any position. The more I learned about power-flow studies, the more scary it is.

This is just a matter of candor. I think some of the things that Craig is concerned about and Donna is concerned about are not necessarily because the utility is being pernicious. The mind-set of the people who put power flow studies together is not economic; they're not thinking about the system as an economic entity. The Commission is unfortunately going to have to get a lot smarter about what needs to go into a power flow study in order to come up with reasonable results about competitive markets than it has done so far. You're going to have to give a lot better direction as to what you want to see than you have done before.

If you leave it to the engineers -- who could care less about the commercial objectives of the company -- they're going to do it in a way which, from an economic standpoint, frankly looks bloody arbitrary and can have all kinds of unintended and unnecessary consequences. That's just a freebie here, that that's something you guys are going to have to take on, because otherwise it isn't going to get fixed. And this isn't a matter of a dictate that says, you know, we think you guys are trying to stifle competition; it's we think you guys don't know how to do load flow studies that are pertinent to the problem you're addressing.

MR. SIPE: I appreciate that comment, because that echoes -- I think we need to get down and actually look in detail at what are in those studies and what we're trying to accomplish with them. Otherwise, I do think it becomes quite arbitrary.

One of the things that did disturb me is, as an additional comment, even though it hadn't been stayed, we were very disturbed to see people come back and say they interpreted that order meaning that we're only going to study them but nobody is ever going to get interconnected under those standards.

CHAIRMAN WOOD: This has been now since November of '01 that that requirement has been applicable to AEP Southern and Entergy. Has anybody taken advantage of that new requirement that was placed on their market-based rate certificate? I don't think there's been much building since November of '01.

MR. SIPE: I can't answer that question. I only know that I've seen filings which said we interpret the Commission order to mean that we only have to study them, we don't have to interconnect them under that standard. I'm not sure whether you'd be getting a false negative at that point, given that filing, anyway.

MR. ROACH: One real quick comment on that. Two things have to happen to get interested in paying for being a network resource: first, you have to know how much you have to pay -- and that's what the study will do, but then you need an opportunity to sell your power, a solid opportunity. Without both of those, you're not going to get a lot of people even asking for studies and you're certainly not going to get a lot of people stepping up and saying we're willing to pay whatever upgrade costs.

MR. O'NEILL: Bill, how would you propose to remedy this problem? There's the engineers who are doing their own thing and somewhere at the company level there may be a conflict of interest in doing the right thing, so how would you propose -- you wouldn't propose that we would do the studies, would you?

MR. HIERONYMUS: No, because utilities seem to be unable to do them for their near neighbors. It really is a craft. And, frankly, Dick, I need to think about it more to give you any concrete answer. But the essence of it -- there are some issues involved, the displacement issue has arisen: do you assume that all on-system resources continue to run? Every time you introduce a new resource, you've got to take something off or you get increment load, one or the other. You've got to get the system to balance, otherwise you can't do a load flow study. It really has to do with what you take off when you put the new resource on. It isn't the case that the new resource is always the same as some other resource in the control area. The sift factors are very different, the flow gates and the impact are very different.

MR. O'NEILL: Can I ask a question? Why do you have to assume that a generator has to come off if one comes on? If they're competing against each other, the one that has the best deal wins.

MR. HIERONYMUS: It's not capacity, it's energy that's flowing. The loads, sources, and sinks have to balance.

MR. O'NEILL: Shouldn't the cheapest energy producer be the one who gets access to the grid?

MR. HIERONYMUS: That's an input to the load flow study, not an output to it.

MR. O'NEILL: You don't have to retire a unit, it's there --

MR. HIERONYMUS: But that's not the way load flow studies are done. Load flow studies say I'm getting the energy to meet load from the following generation bus. You tell the load flow study that's what you're doing. So if I say I'm going to introduce a new bus or I'm going to enhance capacity at a given bus and I don't change load, I have to take something else off. I don't have to take it physically out of the grid; I turn it off. That's the way the studies go.

MR. O'NEILL: But you don't have to know that in advance; the market will determine that.

MR. HIERONYMUS: But to do the study you have to tell the program what to take off.

MR. SIPE: I'll just say that these studies are done and are performed in at least two regions of the country. There is a protocol for doing them. You're correct that you don't have to presume you should retire a unit. You are correct that you do have to make some assumption about what gets displaced. And usually what happens when they're done preferentially is that there are certain units which are simply not going to be allowed to be displaced or won't be displaced at certain times, even though that's not based on any engineering reason per se other than the need to have to displace something if you're not going to increase load.

MR. O'NEILL: Do you feel comfortable with the way the eastern ISOs do their studies?

MR. SIPE: Completely.

MR. O'NEILL: So you're worried about when others do it.

MR. SIPE: No, I'm worried about the standards that are applied are not the standards that those systems use, that the Commission hasn't mandated those standards, and that moving away from those standards and supervision of those studies to make sure that in fact displacement, as those studies are run -- those are detailed studies and the protocols are detailed. There's plenty of room for discrimination down in the details. We have an interested party running the study.

MR. O'NEILL: So you're saying that the eastern ISOs do it right; everybody else does it wrong?

MR. SIPE: You're trying to make something inflammatory which was not meant to be inflammatory. The eastern ISOs perform their studies correctly. In my opinion, the eastern ISOs have the correct standard and other standards are incorrect.

MR. O'NEILL: Could you enumerate the other ones that do it well or correctly?

MR. SIPE: Again, you're trying to misstate what I said. I can enumerate the areas that have an incorrect study: one of them is PJM. PJM operators use that study correctly, but it is a flawed study. So there's a distinction between saying PJM operators are incompetent -- they could do the correct study if the Commission directed them to do the correct study.

It's not a case of even people who don't allow displacement doing those studies incorrectly. The problem is they're the incorrect study to get to the competitive market, which is what I believe that mitigation in the order recognized. Those studies, as currently done, do not allow for entry on a competitive basis and that there needs to be a different standard supervised by the Commission or by an independent party, perhaps. That's certainly a different standard of interconnection to allow competition to go forward.

MR. RODGERS: Let me interject here, if I could. First of all, let me say for the record I've never known Dick O'Neill to interject anything inflammatory into any discussion.

(Laughter.)

MR. RODGERS: Beyond that, I'd like to recognize Ms. Tezak.

Dan Larcamp is available here for your questions.

(Laughter.)

MS. TEZAK: Mr. Larcamp, you're entirely too perceptive generally.

I'm Christine Tezak from Schwab Capital Markets. I'd like to address a comment or two to Mr. Pederson's concern about certainty and what investors look for.

Certainty comes in a variety of flavors. There is certain real value to an investor if you have a default remedy, because the question I get very often is what is the worst-case scenario. If the Commission elected to have a default remedy -- which may or may not be, but could be interpreted by investors to be a worst case scenario --

that would be useful information. I would say there is not an investor I've ever spoken to who would like to preclude the Commission from taking a case-by-case approach to any specific regulatory problem.

I think that Ms. Alexander makes a very important point when she brings up when an applicant comes in with an offer of mitigation and remedy. And I think one of the things some of us on the investor side found very interesting in the recent NRG hearing for the McNeil facility is that there is an offer on the table and it's the offer that is being reviewed in more completeness for legal and procedural purposes and that opportunity is there.

When we ask for certainty from the investment side, we are asking for can they give us a worst-case scenario. I think it's a very salient point. Another issue of certainty is process. For example, one thing that impacts evaluation of the SMA proceedings on any company currently subject to it is what is the reality today? As of December 2001, there was no refund obligation on any sale made, and all three companies still have marked-based rate authority. That means to us the process is iterative; it is going to take time and it is prospective. That makes it more difficult for us, but that is what we all get paid big bucks for, to assess what the impact of these proceedings may be on future earnings. However, it gives us valuable certainty on a day-in, day-out basis, this quarter, next quarter, for all of the quarters that will intervene before you come to a conclusion and a new policy that the sales made currently are not subject to refund.

So when there's certainty, these are the sort of things that I'm asked about: Do the sales that are being made today get impacted? How long does the regulatory process take? Are there clear milestones? How do we evaluate it? It's up to us to discount and revalue companies based on their exposure. But those are elements that can maybe help you make statements, that sometimes seem on their face conflicting, a little more understandable. Because there are certain points we're looking for.

I think when you talk about a default remedy, one of the important things it does for us is sort of give us that's the worst-case scenario and then it is up to the management of each company to determine whether they can do better than that.

MR. RODGERS: Thank you, Ms. Tezack.

Bruce Huddleston of Southern Company, do you have a comment?

MR. HUDDLESTON: Yes. I actually have a question for Dr. Hieronymus, sort of a follow-up to Chairman Wood's question.

You said if there were enough people or enough entities paying market-based prices after the utility had been mitigated at cost-based price, then there would be incentives for competitive entry. Suppose you were in a situation where you still had an obligation to serve areas of non-retail access and say that the utility that had the retail service obligation had a 15% reserve margin that it was obligated to keep.

And let's further assume that 15% reserve margin was greater than the size of the wholesale market. If that integrated utility was capped at cost, would there ever be a reason for competitive entry if all wholesale customers could take advantage of that cost-based power in the reserves of the vertically integrated utility?

Did that make sense?

MR. HIERONYMUS: If I understand your hypothetical, I guess my first response is if you need all your power you haven't got any to sell, but obviously you would have some to sell off-peak.

MR. HUDDLESTON: Even on peak, you still have 15% reserves if everything is operating.

MR. HIERONYMUS: Okay. Your hypothetical says that we never get to Chairman Wood's situation. You're saying that there is no margin beyond the plateau. In that case, obviously, no, there's no price that will attract entry.

MR. HUDDLESTON: Okay.

MR. RODGERS: If there's no further comments, why don't we conclude this panel?

We will reconvene at 1:00 for our fourth and final panel.

(Whereupon, at 11:55 a.m., the technical conference was recessed, to reconvene at 1:00 p.m., this same day.)

AFTERNOON SESSION

(1:05 p.m.)

MR. RODGERS: Why don't we go ahead and get started, if we could?

(Pause.)

Good afternoon. This afternoon we're going to be holding our fourth and final panel on the Supply Margin Assessment Technical Conference. The focus of the panel this afternoon is on data and miscellaneous issues, "miscellaneous issues" being those that perhaps don't squarely fall into the category of the other three panels.

The data aspect of this panel is to focus on the somewhat technical but very important issues associated with how does one come up with the data that's needed to run any kind of screen. Again, one concern that the Commission Staff must constantly deal with is the need to act on initial market-based rate filings with 60 days. So we need to have a test and data accessibility to will enable Commission Staff to prepare orders for the Commission in that time frame.

There's also issues on this data panel associated with not equal availability of all data to all market participants. Related to that is the issue of confidentiality. We're looking to this panel to help the Commission give guidance on how perhaps we can deal with that issue.

Also, the issue of data definitions and whether we should be conforming our definitions to NERC terms, where possible. We're interested in sources of data, quality of data, and accessibility of data.

With that leadoff, I would like to turn our attention to our first panelist for this afternoon, who is Rodney Frame, who was with us yesterday afternoon. He is the managing principal of the Washington office of Analysis Group.

Welcome again, Mr. Frame.

MR. FRAME: Good afternoon. I'm a managing principal of Analysis Group. We're a consulting firm, a privately-owned microeconomic finance and strategy consulting form with approximately 300 employees spread across 10 offices, including Washington, where I'm located. I appreciate the opportunity to be part of this panel. I have prepared SMA and other types of market analyses for numerous applicants on numerous occasions, and these analyses have faced many of the issues that have been teed up for this panel.

I'd like to begin with what I think maybe is the easiest issue, it's one of the non-data ones that's for the panel. The agenda asks: "How should the generation-dominance screen be used -- as a definitive test or an indicative test?" Then: "If indicative, does screen failure result in a hearing or additional studies?"

I think the question almost answers itself. Market power investigations can be difficult, time-consuming, costly, and not necessarily determinative of key market power questions, even in the best of circumstances. There's a lot of money and time thrown at the process. So no single, simple, low cost easy to implement screen ever is going to produce correct predictions about the potential for the exercise of market power in wholesale electricity markets at all times and places. There's always going to be the possibility for a false positive and false negative reading. And I think we'd be wrong to ground policy on the false notion that that will not be present.

I think the real question is how to take the possibility of the potentially false readings from the screening indicator into account? I think of this in terms of assigning the burden of proof. If an applicant for market-based rate authority passes an economically sound screen, then the burden of proof should be on those that oppose market pricing for that applicant to demonstrate with additional evidence that the exercise of market power in wholesale electricity markets may ensue if that market-based rate authority is continued or granted.

Conversely, if an applicant for the wholesale electricity market-based rate authority fails an economically sound screen, the burden would be on it to demonstrate with additional evidence that the exercise of market power in wholesale electricity markets is unlikely notwithstanding the indication of that screen. It would be simply wrong to accept the results of the screen as a definitive indicator.

That stated, what types of additional evidence might be used to rebut a false finding? I'm pretty sure there's not going to be a standard recipe that's for both applicants and interveners. A useful focus would be on the practical ability and economics of the potentially aggrieved smaller systems in the applicant's control area where the screen presumably has been failed to obtain their bulk power requirements from sources other than the applicants.

And we heard examples yesterday, the gentleman from North Carolina, and, today, there was an example from the gentleman from Golden Spread. Those are the types of situations that you would want to look at where there's a screening failure. You look at what those system requirements are, what are the resource available to meet them, and what in and out of control area options are available to them.

If we tee up the possibility of examining additional evidence to address potentially false readings, the question naturally arises as to what you at the Commission are going to do with this additional evidence, and, in particular, whether the time and expense of a hearing might be required.

I guess it's correct that in some cases a hearing will be required. I hope that's not going to be too many of those cases; I'm not sure. A hearing is the worst thing in the world, given the alternatives, which may include a bunch of false positive readings and unnecessarily costly litigation on the one hand and, on the other hand, the adverse effects of actually letting the exercise of market power go on, if that's what happens.

Let me turn more specifically to the area of data concerns. I think it's important for the legitimacy of a screen that the data used for it be publicly available, or at least largely so. The favored screen that I have, as we put in the written comments and discussed a little bit yesterday, is a modified form of the existing SMA -- "modified" meaning to take into account applicant's load obligations. For the most part, I think that the data from such a modified SMA are readily available or can be estimated in largely non-controversial fashion from existing data sources.

The concerns I heard yesterday about not being able somehow to segregate applicant's generation into committed buckets and uncommitted buckets, in my view, are simply off-target. I simply don't think there's any great need, for purposes of implementing a well-rounded market power screen, greatly to expand the Commission's existing data collection efforts. Thus, if there is going to be such an expansion, I would urge that it be carefully focused so that there is a clear nexus between the type of new data that is collected and the identification of market power problems.

As an example, there was a discussion yesterday as to whether we could use the concept of an economic dispatch of the system to determine if the markets were behaving competitively. I think if the Commission goes down this path, it's got to be done correctly. There's an awful lot of reasons out there why a cursory look at the results of an economic dispatch might suggest, without further information, that the dispatch has been efficient. But then you have to go look at the underlying facts to see whether that's the case, and there's an awful lot of facts that you have to look at, so that this can't be done naively.

The list of things that could cause generation seemingly to be out of merit, the dispatch to be out of merit, without further examination includes things like the need for area protection, transmission line loadings, creditworthiness perhaps in some situations, environmental problems, equipment problems, maybe even 20/20 hindsight looking back today -- if today was a little hotter than we expected, we wish we'd committed a different set of units but we didn't because we didn't know that it really was going to be 102o instead of merely 95o.

I say that most of the data that is needed for the modified SMA I think is readily available. Let me mention a couple of areas where a little bit of work might be needed: TTCs -- the SMA and all of the alternatives in the Staff papers rely upon TTCs. I think that's the right thing to do. But there are some areas of the country where TTCs are not available, on OASIS sites in particular, in the footprint of the Midwest ISO. So where the TTCs aren't available, you have to pursue other options. One which is simply to compute them, have them computed for you. I'm not an engineer, but I don't think that's something that's particularly difficult to do.

Another possibility would be to use somewhat equivalent data from seasonal assessment studies like FTC TTC data.

And a third possibility would be to require that this data be developed in areas where it's not published. One of these alternatives will have to be pursued.

There has been some discussion about simultaneous import capability -- should we simply sum the TTCs or do we need to scale them back in some fashion? Probably in some control areas that is really important. If a control area has a lot of interconnections to the outside world, it's almost certainly true that you're not going to be able to sum them all; it's going to be less of a problem if the interconnections to the outside are fewer and they tend to be more discrete.

If you want to have simultaneous limits, the data are not available off the shelf, but I do believe they can be included -- and again, that's not a real complicated process. There is the possibility for some dispute about just how to do it and what the results mean. I think that's something that could be taken care of over time.

I always think that a simpler fix is just to never let the amount of import capability exceed the load in the control area, because it doesn't make any sense. So if you had one of these well-interconnected control areas, just cap the total at the load level and that would be a quick fix.

I think the final point that I want to mention in the limited time I have concerns planned outages. The screen measures that are discussed in the Staff paper each will be discussed on a month-by-month basis -- that's different from the SMA screen. In my view, for many applicants there's going to be little additional information about market power that's going to be gleaned from this type of month-by-month analysis as opposed to just a peak period analysis. So I do question whether it's useful as a required component of the screen. I think in most cases if an applicant passes a well-conceived screen at the peak -- and it was discussed earlier today -- at the peak, when supplies are tight, then there's very little likelihood that it's going to fail at other times. You can do the examinations then, but I just think as a practical matter you're not likely to find any failures if the entity passes at the peak.

Of course, I would allow -- if applicants failed the screen and they're subject to mitigation, I think they ought to be allowed to do studies at other times to demonstrate that they shouldn't be mitigated at those other times.

That stated, if there is to be a month-by-month approach -- and I don't think that's necessary -- it is going to be necessary to have information on the month-by-month loads and outages. I think the load data is relatively easy to assemble, but it's not likely that information on actual planned outages is going to be readily available. I think suppliers appropriately are like to guard as competitively sensitive information on actual outages. I think this is really not a big problem.

If you want to use outages in the analysis, you can get generic data on outage rates from standard data sources and plug them into your analysis. We've been making assumptions about when the outages occur, generally putting them into the off-peak periods. I think as long as you're willing to live with the substitution of generic outage rates for actual outage rates, I just don't believe that that's a big problem.

I would like to thank you for the opportunity to let me speak today. And, having sat here for the last two days, I've learned quite a bit and there have been a lot of new ideas to think about, and I'd like to do that. It's certainly been useful to hear the position of others in the other panels, and I look forward to hearing what my colleagues on this panel have to say.

On behalf of Southern Company, we would like to express our desire and intention to basically assimilate the materials, the knowledge that we've learned in the last couple of days, to take that into account and prepare some additional comments, hopefully with the goal of making our positions more clear and taking the other views appropriately into account.

Thank you for your time.

CHAIRMAN WOOD: I'll add in here, Mr. Rodgers and Commissioner Kelliher and I have discussed -- we would like to offer that opportunity to you and anyone else, whether they're in the docketed proceedings or not. For the next 21 days, we'll hold the record open. I think by filing supplemental comments, which thankfully would reflect some digestion of what we've heard here today and yesterday, great. We'll put out a notice to that effect.

MR. RODGERS: Thank you, Mr. Frame, for those comments.

In our never-ending attempt on Staff's part to keep panelists off-balance, we are actually going to go back to the same format that we used yesterday. That is, to open up the Q&A for Commissioners and Staff at this time after each panelist has spoken, rather than after the last panelist has spoken. So I'll go ahead and kick us off here.

One thing I'm wondering, Mr. Frame, is you suggest that whatever market power tests the Commission uses should not be definitive, and I think there's certainly some appeal to that. But one downside to that is that it would seem to leave more regulatory uncertainty out there for market participants. An entity may not know where they stand if there's not a definitive test that they can pass and be assured that they will be guaranteed of getting market-based rates. Would you like to comment on that?

MR. FRAME: I guess I don't doubt that that uncertainty will be present. You just have to assess the benefits and costs. What are the costs of living with that uncertainty? In an ideal world, we wish that it weren't there. On the other hand, isn't it important to get it right?

We had such a wide view on the types of mitigation proposals that might be acceptable, I can imagine if the wrong mitigation were implemented in a situation where there really wasn't market power concerns, that there would be the potential for damage. And I would flip that around: there could be damage if market power was allowed to proceed in the face of a screen reading that said that it was very unlikely. It's not a perfect world, and you have to live with those considerations.

MR. PERLMAN: Just to follow-up on that, should the rates then go into effect subject to refund or something like that? And how would we set a refund for it if it did turn out that there was market power?

MR. FRAME: To the extent you're getting into a legal place, I really can't go. I would be very uncomfortable with rates in effect subject to refund. I think that's a ticking time bomb out there. That's the kind of uncertainty that I think you could avoid.

MR. RODGERS: If I could comment on that, I think you also suggested earlier in your comments that for situations where it was not clear whether an entity had market power or not, the Commission could and should investigate further by setting hearings. One concern I have with that is, if there's not some refund condition that attaches to the rates during the time that a hearing is going on -- and a hearing can take quite a while -- I'm wondering about the effects that may have on the market. I'm also wondering about whether -- because we have a large number of market-based rate filings here at the Commission, as opposed to merger filings -- we only have three to four merger filings a year, but we have many dozens of market-based rate filings a year. Typically I think that we could potentially find ourselves in a situation where we could have lots of hearings going on on these issues if we, in fact, needed to set a lot of marginal cases for hearing.

MR. FRAME: I hope that doesn't happen. I would expect there might be some that go to hearing, but I think that some would be considerably less than the universe of potentials. If the types of mitigation proposals on the table are reasonable and accounted for legitimate needs, and if there was a market power concern accounted for the legitimate needs of the buyers, I don't know why there quickly couldn't be some agreement on what would happen to avoid the hearing entirely.

Yes, it would be a problem if whatever the Commissioners' number was yesterday, 75 things had to go to hearing. That would not be a very good outcome. But I feel that things can converge a lot more quickly.

MR. RODGERS: Another thing you mentioned, Mr. Frame, was that you did not believe it was a problem to be able to divide generation capacity between that which is committed and uncommitted. If I understand you correctly, you would tend to support a market share screen that was based on uncommitted capacity and which took a snapshot at the time of the annual peak; is that correct?

MR. FRAME: You said "market share." I didn't say "market share." I said "uncommitted capacity screen." Yes, otherwise, yes, that's my position.

MR. RODGERS: At the time of the annual peak though, that would be the very time that a vertically integrated IOU would have the least amount of uncommitted capacity typically.

MR. FRAME: That's correct. For that reason, I think it's a rather stringent test.

MR. RODGERS: I'm not following the logic of that being a stringent test, because at that time the IOU would have conceivably no uncommitted capacity and, therefore, would presumably have a much better chance of passing a screen than if the screen were applied at other times.

MR. FRAME: Let's think about this. We have the peak demand time and we've got the applicant's load and we've got the applicant's resources and we subtract them out. When we go to the off-peak periods, the applicant naturally has more uncommitted capacity but so does everybody else in the market. The whole amount of capacity chasing the load has expanded greatly. It's not likely that the applicant is going to somehow all of a sudden become pivotal in those other periods.

You couple that with the fact that the load -- the off-peak periods -- and off-peak might be the wrong word, it might be the peak in April or the peak in October -- but the load at those times is naturally that much less, so there are many more resources chasing that load. So it's not likely, in my view, that the applicant is going to be pivotal at those times.

Now, what I have a concern about -- and we discussed this somewhat in the prepared comments -- is going to the unfamiliar capacity test, going to a 12 -- month-by-month measures but, at the same time, going to a market share approach. Because I am concerned that the applicant will have much more uncommitted capacity at these lower demand times. The rest of the market won't have any more. Because we've got whatever transmission camp is coming into that market, that transmission camp might be binding at the peak. If you could only get a thousand in, maybe you could only get a thousand in at the off-peak. So the applicant's relative importance under a share computation increases as the load declines. The share would just give you precisely the wrong inference. The markets are more competitive then and the share could suggest just the opposite if that played out as I said.

MR. O'NEILL: Can I just follow up?

You were very careful to make the number for the utility as small as possible, but you seemed to like the idea of TTC, which is probably the biggest possible number for the competing supply. For the sake of not having to go to hearing, do you think we should require a history of actual transactions across the interface to give us sort of a feeling of whether TTC is actually available?

MR. FRAME: A couple of things: I did suggest that if the TTCs, if there's a simultaneous limit that ought to be applied, you can't just go summing the TTCs. I'm not opposed to your getting the information on the historical transactions; I'm not sure it's going to take you very far. I'm concerned that if there was a historical transaction, that the real question in a market power sense is what supplies are available if I try to raise price and what happened to exist historically might not be what might be available if the entity with market power tried to raise price, depending of course on the elasticities. I'm fine with the collective measure, if you think that's important.

MR. O'NEILL: But if we think there's a lot of competition -- that is, a lot of potential competition and, in fact, the evidence from historical periods shows that there isn't any competition, either the competition we thought was there is too high-priced or they're not getting to market.

One of the things -- we meet with the anti-trust folks on a regular basis, and they have harped on it for at least the last five years, maybe more -- is to look at the actual market, to look at the commercial transactions. If they don't sync up with these data, like the TTC -- which I don't particularly have a lot of faith in myself -- you've got to ask why. So in the interest of actually moving the process forward, maybe you file the information as part of your case in chief and we don't have to go to hearing.

MR. FRAME: There could be so many reasons why the actual transactions were less than the TTCs. I just imagine the situation of a wholesale customer inside the control area that is being served by the incumbent utility at a rate that it's very happy with and it has not gone out into the market to search the price; if you had the information on the transaction, you could look at and say Hey, they're getting a pretty good deal. So I look out into the actual historical inflows, and I don't see any. What does that tell me? Does it tell me that there's market power or that it's being exercised?

MR. O'NEILL: It could.

MR. FRAME: It could. But it could also tell you other things.

MR. O'NEILL: What does TTC tell you?

MR. FRAME: I think what we're trying to do is to come up with -- I think it's a simple screen.

MR. O'NEILL: It's simple, all right.

MR. FRAME: If that's the task, to come up with a simple screen, you can point out that in times the "what-ifs" are important. There's a lot of "what-ifs."

MR. O'NEILL: We can always do simple screens, there's no doubt about that. Should it be a simple conservative screen or should it be a simple liberal screen?

MR. FRAME: I guess in my view it should be a simple well-founded screen.

MR. LARCAMP: I guess one problem with TTC is, since 888, we started doing OASIS. Time after time after time we see that there's not even really an ATC available. Why should we go with a very liberal -- in the face of the evidence that ATC in most systems comes nowhere close; if ATC is available, comes nowhere close to being TTC.

MR. FRAME: I think we're running the risk of confusing the test and the mitigation, or the test -- maybe the primary test and the secondary additional looking at information.

What I suggested is if somebody fails the test or passes the test and the intervener disagrees, let's look at the practical alternatives that the small systems that might be affected to them. Now we're going to look at things like whether they had ATC back up to where the original test is.

I think you're hypothesizing a situation where you've got a lot of TTC that has been used in the test, but out in the real world somebody wants to transact, there's no ATC. Okay. Somehow the TTC capacity is being used and it's getting into the control area and I can't sit here and tell you how that's being used in all cases. It may be by applicants to bring in a remote source, but it may also be by the very same customers that might be subject to the exercise of market power or deemed to be subject to the exercise of market power under poorly conceived screens.

MR. O'NEILL: TTC doesn't say that it's being used. There's some potential to be used.

MR. FRAME: I was referring to the difference between the one and the other. If the TTC on a path is 1000 and the ATC is zero --

MR. O'NEILL: Are you saying there's 1000 coming across that interface?

MR. FRAME: There's 1000 that's not available to the market place. Now we could get into whether it's firm or non-firm --

MR. O'NEILL: Our assumption is that it's competing. If ATC is 0, the assumption is that all the TTC is actually competing in the market.

MR. FRAME: I think if the TTC was being used by applicants, if that could be demonstrated, then you would have an argument for pulling that portion out; that is, it was being used by other marketplace participants. I don't think that flies. That's something that's available to serve the market.

MR. O'NEILL: I don't think the history of TTC and ATC argues that if ATC is 0 all TTC is being used by somebody.

MR. FRAME: Could be used.

MR. O'NEILL: But if ATC is 0 and TTC is a large number, why is the answer no when you go to ask for --

MR. FRAME: Because the ATC is 0 --

MR. O'NEILL: And because all the TTC is being used?

MR. FRAME: You've got TTC then you've got your TRM, your CBM, your uses.

MR. O'NEILL: Why don't we net out the TRM and the CBM?

MR. FRAME: For what purpose?

MR. O'NEILL: Market power analysis.

MR. FRAME: If they're being used by applicants and not available to the market, and your concern is about a capacity transaction, that might be a good idea. If your concern is on the energy side -- and, indeed, I sense that much of the concern is on the energy side, because that's where much of the mitigation discussion focuses -- if that is the concern, I'm not sure it would be appropriate to net that out.

MR. PERLMAN: Would the answer be to take TTC at least and subtract CBM, which is the amount the applicant has reserved for reliability for its own purposes? Then that part will have been not even available to the market for them to reserve and to use alternatively. You would know that the applicant had not allowed that component of TTC to be made available and you'd have something more representative along the lines of what Dick and Dan were talking about, would you agree with that?

MR. FRAME: We've probably gotten a little loose on the applicant and then didn't make --

MR. PERLMAN: The transmission owner.

MR. LARCAMP: Doesn't ATC take out CBM, because it's not available?

MR. PERLMAN: I think what I'm just saying is that Rod is saying is that you have TTC, a subcomponent of that would be CBM, and that you could have other uses that people inside the control area who weren't the TO might have reserved the transmission system for. At a minimum, I would think you would agree from what you've said you'd take out the CBM and come up with a smaller number. Because that was something that the transmission -- or applicant had not made available to the marketplace for the reasons that CBM was created, and, as a result, TTC would overstate the import capability that would be available.

MR. FRAME: If I'm looking for a firm-type analysis of capacity transaction, I don't think, if I was focusing on energy, I'd want to do that. I think you could import energy against that.

MR. PERLMAN: I guess, just as a logical matter, I would expect in a peak period -- which is the point in time you want to focus on -- that the transmission system would be stressed, as well as the generation system. At that point in time, that's a bad assumption, that the import capability they were relying upon for reliability they'd be utilizing. Is that a bad assumption?

MR. FRAME: I don't think that necessarily follows. I think you'd have to look at the facts, but I think at peak times you could find situations where all the generation is used -- the generation is needed locally, so there might actually be less from here to there because load is up in both places.

MR. FRANKLIN: Mr. Frame, along those same lines, what I'm hearing you say is -- if I can just quickly repeat kind of your position, and we can say yea or nay to this. What you're saying is basically you're okay with taking out maybe the TRM or CBM out of the TTC. Your concern is to keep in the firm point to points that are done by non-affiliates -- or that are reserved by non-affiliates. You probably have generation outside Southern Company --

MR. LARCAMP: Isn't that in the ATC calculation as well?

MR. FRANKLIN: The TTC -- the difference between the ATC and the TTC is basically network reservations. They can have coal units in West Virginia and nobody's ever going to get that reservation as long as that coal unit's running. They're going to have their network reservation coming into their ties, if they have any generation outside their control areas, which is not totally unusual. It happens like with West Virginia -- it's got a lot of coal and whatever, so people pipe that in across the ties. So that would definitely need to come out.

But I think what he was saying was a lot of times you might have one of the unaffiliates or the merchants, you know, that have reserved and historically reservations across the ties. I think that's what you're saying. That should be put back in.

MR. FRAME: I may have lost sight of the question in terms of the exchange between you and Mr. Larcamp, but the stuff that's available to the marketplace is the stuff that I think that's the goal, that's the stuff that ought to be used.

MR. FRANKLIN: And you would agree that network reservations would not be -- or a TRM or a CBM would not be available during peak periods?

MR. LARCAMP: Isn't all the stuff in the marketplace -- what if that marketplace supply is for a load-serving entity? They can't make that available any more than the accommodating utility, because they've got to use it to serve load. Isn't that portion of the available capacity that's available for the energy-only sale, if we're talking about market power and the energy-only sale?

To the extent that Mr. O'Neill, for his client, is a firm customer and Golden Spread has reserved capacity, aren't we over counting the competitive effect if they need to use that transmission to serve their load?

MR. FRAME: I perhaps didn't follow that question as well as I might have. It seems to me that the test that I would have in mind would look at applicants' uncommitted capacity and see if that's necessary to serve the market's load. The TTC, that other entity in the control area, the load it might be serving is part of the market's load, in fact.

MR. LARCAMP: So we're looking at the load of the vertically-integrated utility with its control area as if it is responsible for meeting all of the full requirements loads for anybody that's embedded within its control area?

MR. FRAME: No, we're asking whether its uncommitted capacity is needed for those loads, can those loads get what they need from other sources, meaning their own generation or, the subject of this discussion, looking out the interties to the world.

Your particular example was a situation, I thought, where one of those loads already had reserved some transmission capacity. And, yes, I want to count that stuff that's already been reserved as something that's available to serve them.

MR. LARCAMP: It seems to me the Commission has designed a regulatory program here if TTC is the most liberal in terms of calculating alternatives that can serve the load within the control area.

Would it be appropriate for the Committee, in looking at a regulatory program, if it selects that liberal measure perhaps to be less liberal in terms of when it might impose some mitigation while a dispute as to a screen failure is resolved by looking at the applicants' individual proposed remedy for solving that?

I mean, we've got a 60-day clock here. If you fail the screen, Staff is looking at how can we allow business to go forward until we can make a recommendation and the Commission can either find that the proposed mitigation solves the problem or doesn't solve the problem?

MR. FRAME: I'd rather you clean up the transmission measure as best you could.

MR. LARCAMP: So we suspend the application for the full seven-month period, having the hearing, and decide until that happens you can't transact at market-based rates?

MR. FRAME: I didn't recommend that you suspend it for seven months.

MR. LARCAMP: If we fail the screen and our Commission is charged with ensuring that all rates and charges are just and reasonable, how do we meet that statutory charge in the example of the screen failure before we conclude that the individual proposed mitigation is sufficient to mitigate the screen failure -- or the problem the screen failure identifies?

MR. FRAME: I guess my preferred alternative would be to get the transmission numbers better. If you're saying you don't think the TTCs do that good of a job, then put the burden upon the Applicants to come up with better, more representative numbers, and give them some standards and guidelines. Tell them whether you're interested in firm or non-firm TTCs. Tell them if you don't want that CBM in there, tell them you don't want it in there. Let them come in that way. But there's no reason to set it for hearing on that basis. Let's get those numbers right.

MR. RODGERS: We had a great back-and-forth exchange. We appreciate very much your thoughts on this, Mr. Frame. In the interest of time, I'm going to move us on to our next panelist, and maybe there will be an opportunity to come back and ask more questions of Mr. Frame later.

Our next panelist is Dr. Joe Pace, Director of LECG, LLC.

Welcome again, Dr. Pace, appreciate it.

MR. PACE: Thank you. Once again, I appreciate the opportunity to participate in this technical conference this afternoon concerned with data issues and other miscellaneous issues.

The starting question you posed had to do with the role of the proper screen analysis. I covered that subject in the written statement that I circulated yesterday. And, as you would expect, took the appropriate position that it should be just a screen and not a definitive test. I don't think I need to say anything else about that. I concur with everything Mr. Frame said on the subject of the role a screen analysis ought to play. So I'd like to turn directly to data issues.

Let me begin by emphasizing that one of the most effective ways to reduce data collection burdens is to adopt a very abbreviated screening analysis for relatively small market participants. We've all spent a lot of time over the last day and a half worrying a lot about big utilities, implicitly big utilities with big native load obligations. But there are a lot of other people out there and a lot of utilities outside their host control area that, in my opinion, ought to be given a pretty easy way to pass and reduce data burdens.

For example, and I suggested this in my written statement: I think you could adopt with confidence a greatly simplified screen process for suppliers where that owner controls less than 10% of the particular generation resources in a given area. This particular test would only look at applicants' resources and the total capacity physically located in a particular area, control area, or recognized subarea. Transmission limits, load levels and outage rates can be ignored.

One thing again that I would counsel you to think about is setting up a really conservative screen for small applicants that requires almost no data to do and gives them a way to walk away.

Now let me turn to the data acquisition issues that are likely to arise in carrying out any of the other screen analyses that are now on the table. The first is transmission limits. You know, we had a pretty good discussion with Mr. Frame on that.

In my view, getting reasonably live transmission limit information is the key to preparing a good screen analysis. Transmission operators should be required to post sufficient data to allow a determination of realistically usable transfer capability where control-area-to-control-area TTCs are posted. Any amount of that capability that is not available for scheduling transactions should be identified, whether this reflects a set aside for a CBM or TRIM or loop flows or anything else.

Where control area ATCs are provided or can be calculated, scheduled transactions into and through the control area are already embodied in that ATC calculation and should be provided. If you're going to use ATCs, you've got to be able to identify the actual transactions that are coming in and have already eaten up transmission capacity, so that you can add that back in.

Beyond this, substantial interdependencies between transmission limits need to be identified and posted. Again, I think this should be done on OASIS. I'm aware that there are examples on OASIS where it will explicitly have a statement that, you know, if you book a transaction on Path A, we will also decrement the transfer capability, the available transfer capability on Path B. That's the transmission operator telling you This is a simultaneous limit. I've seen some that are even more sophisticated, and they say for every megawatt booked on Path A, there will be a 0.7 megawatt reduction in available transfer capability on Path B.

One of the ways that you can help us poor practitioners, as Mr. Henderson liked to say, to help you is to require that good data be reported in the OASIS, so that we can get at what can realistically be used. You can come at that from the top down, TTC minus what you can't schedule, or you can come at it from the bottom up, ATC -- as long as you've got the information on everything that's already been scheduled and is eating up capacity. Beyond that, in our experience, there are going to be some cases where neither one of those measures is available. There I guess all I can say is you've got to give us poor practitioners a way to address that. We have, in some cases, had the engineers calculate first contingent incremental capabilities for that. I think that's a good alternative, but you've got to give us a way to do the studies.

Turning to the internal transmission constraints, as I believe I suggested yesterday, applicants who are control area operators should be required to address significant relevant internal transmission constraints. I want to stress the word "relevant." A constraint is relevant only if there is a potential shopping or wholesale customer materially affected by that constraint. You have lots of internal constraints that in some way affect the dispatch of the system and its service to native load retail customers. But unless it affects a load that realistically is going to be in the market or likely to be in the market shopping, it's not a relevant constraint.

In addition to good transmission data to carry out any of the screen analyses that are on the table, we need load data for the destination market and for directly interconnected areas. Form 714 data cover much of the country. Usually we don't think of load data as presenting much of a problem, as Mr. Frame said, but I would argue that some clarity could sure be helpful in using the data intelligently. In particular, you need to know what full and partial requirements loads are included in the calculations we're reporting in 714 and whether any non-requirements wholesale contract loads are included in those calculations. I've been involved in cases where that was a very thorny thing to try to figure out.

And if there are large full and partial requirements loads in the area, that can be a very important thing to understand. You need to know, when you think of a load data from the hour on 714, well, who's in it? Is it the person filing the form or is it him plus all the full requirements customers. If he's got partials in there, does he have their total load in there. I would encourage you to think about enhancing the data requirements a little bit so that you know more clearly what numbers you're looking at. The hard copy 714 contains some of that information, but it's not accessible electronically is my understanding.

Next, let's consider the measurement of uncommitted capacity. Here my only comment is as long as the applicant can calculate uncommitted capacity, other people in the first tier area -- by contrasting the total area load with the total capacity, total non-applicant load with total non-applicant capacity -- this is a do-able task. I think that's the way the Staff paper envisions it being done.

In contrast, trying to match up individual or non-applicant load obligations with specific resources dedicated to meeting those obligations, trying to figure out what's committed and uncommitted that way is a near impossible task and not a path we want to go down.

Another data requirement associated with the screen analysis described in the Staff paper is generator outage information. I agree precisely with what Mr. Frame said on that. As long as you are willing to accept generic outage rates and relatively simple algorithms for allocating those outages by season of the year, this is not going to be a big problem. This can be done. If you are, in fact, to require sophisticated outage analyses, we need to get some seriously good data on planned outages and exactly how they're going to be allocated. That will turn the task into something virtually impossible.

The last data issue I want to touch on is the comment that was frequently made yesterday, frequently repeated, that we can't recognize retail load obligations in the screen analysis because it's too difficult to figure out how to measure those obligations and apportion the capacity between retail and wholesale. Poppycock was the best word I could come up with that I could use in the hearing --

MR. RODGERS: Am I going to have to pull out this electric buzzer for your seat here?

(Laughter.)

MR. PACE: No, I'm not going to get any nastier than that. There is no significant data measurement issue here. If you want to look at the capacity that is not committed to retail loads during non-peak seasons or off-peak periods, that can easily be done. If you decide, looking at a pivotal supply analysis or whatever from the peak snapshot doesn't give you quite as much information as you need to recognize retail loads, well then, fine, tell us to bring you ones that look at peak periods for other seasons. Tell us to bring you a snapshot that looks at the average off-peak load condition. We can do that. That is a far better thing than simply to say Because I haven't made those decisions, I'm just going to throw out the native load obligation and not deal with it in the analysis.

So that's certainly what I would encourage you to do there. If you would assume more snapshots of how the native load obligation affects the market than just the peak hour, all you've got to do is tell us to do that. That's not a hard problem. There's no measurement issue here that ought to be an impediment. With that, I'll stop.

MR. PERLMAN: One quick follow-up on that, just to make sure I understand: the actual peak hour of the hottest month, assuming there's summer peaking, may free up your generation -- you may have a number of other days in that month where it's not quite to that level and would free up a lot more generation to compete, even though sort of in a peak period, you may want to evaluate something other than just that peak hour. You're saying the data, if the Commission is interested in looking at it, is readily available and that type of submission could be made?

MR. PACE: Yes, I think in general we could probably give you almost anything you wanted. If you want to say Tell me, measure the load that prevails during the 93rd hottest hour of the year, I think we can do that. So data measurement is not a problem.

I think the problem is going to be once you get outside peak periods, how are you going to do a pivotal supplier test in a non-peak period and have it make any sense at all? I think exactly what you do with these additional tests that we could bring you is a more interesting question. But I would hate to see somebody go away thinking that we have a data measurement issue that prevents us from addressing the retail load obligation in a sensible way.

MR. PERLMAN: The entity that has access to the data is the supplier to the retail load. That data, as generated, it would be that applicant who would bring it forward?

MR. PACE: Yes.

MR. PEDERSON: Is there any problem making that retail load data publicly available? Would that be a concern?

MR. PACE: Generally I don't think so, in the following sense: generally speaking, it is -- the peak load that a major utility has is usually a reported thing. If nothing else, you can use the load shape on the 714 to figure it out. But again, the other point is, any applicant that wants you to rely upon their native load commitments and factor that into the analysis, if they can show you they don't have a market power problem, they certainly ought to put the data on the table for you to examine.

MR. LARCAMP: It almost sounds like you're suggesting the Commission require the control area operator -- and I'm using it in a transmission function -- that has a wealth of information file more explicit information under the statutory directive that they annual file information on the operation of the system and I believe its known constraints, is the statutory language which would be available for use by any applicant, affiliated or non-affiliated, wanting to sell at market-based rates within that geographic area. Is that a fair statement?

Which would be a way that the Commission could be consistent with its directive that there be a separation of function between wholesale generation and transmission function by having the transmission function file a wealth of information about how these systems have actually been operated that would be used with anyone that's seeking market-based rates within that geographic area.

MR. PACE: I can't honestly say I have thought that through. I was thinking of it more in the sense that a particular applicant is coming to you seeking market-based rates and is in possession of this information.

MR. LARCAMP: I'm thinking of those poor consultants that are trying to get access on behalf of independents and they're not affiliated with the control area operator. To get access to that information, why couldn't the Commission just say Control Area Operator, you file it and we use that consistent set of data for purposes of analyzing every one until the next update is filed?

MR. PACE: First, let me say that I have a lot of sympathy with that poor consultant; I'm one of them. And I'm often asked to do market studies where I'm not representing the utility that's there; I'm in fact representing an independent who doesn't have great information. In the abstract, I don't have any problem with that suggestion. The only thing that bothers me a slight amount is it's easy for me to imagine in a particular fact context of an applicant's filing how it can hold in on internal transmission constraints, for example, that are indeed directly relevant because they directly limit somebody's shopping options.

As long as it was clear that the control area operator is an independent report and that's all they're being asked to get, and it wasn't being asked to engage in lots of generic discussions of internal constraints -- some of which may not have any relevance -- I don't think I'd be too troubled by that.

MR. FRANKLIN: Dr. Pace, again, my sympathies to all of you. I have been struggling with this issue for quite a while and this data issue is a cumbersome issue. In fact, we were asking a lot of questions this morning from you and we appreciate your being here but there are a couple of comments that have been made and I'm not sure how we would go about assembling the data.

For example, if we take the native load off the books, so to speak, and the native generation that serves that native load, would that be a snapshot in time? For example, if there was a car manufacturing facility that was currently with the transmission providers affiliate generation, would that qualify as native load, or is it in the market? That's the first question.

The other question is if we treat the native load that way, should we also treat merchant plants who have a portion of their generation earmarked in purchased power agreements and how would that information be gathered in order to be fair? You'd have to do that out at least one or two tiers if we're going to do all this analysis of how much we can get into the area to prevent market power.

And the third question: I heard it stated that the transfer capabilities are easily calculated. That is true. And this is the key: once you have a clean database and all the monitor lists and all the contingency lists. So are the proponents of doing flow-based analysis -- in the interim are they going to provide for public consumption a load flow database with all their assumptions laid out and a monitored line list and contingency lists and have the TRM basically cross-reference based on what that portion is reliably being held for? Those kinds of things: a well-documented, clean database. Because that takes a significant amount of time and a significant amount of manpower, it's been my experience anyway.

MR. PACE: If you weren't on the Commission Staff, I would object to that as a compound question.

(Laughter.)

MR. LARCAMP: Overruled.

MR. PACE: Let me take the part of it that I remember --

MR. FRANKLIN: The first one was whether you consider a power plant or a manufacturing facility that's currently being served by wholesale contract with its transmission provider -- do you currently consider that to be in the market when maybe in the past it wasn't or maybe its interested in the future, testing the waters. Do you consider that part of the market?

MR. PACE: Yes, I think if you're looking at a particular obligation, the question is for what time period does that obligation run?

If I had the information -- if that's something I had to figure out and I had the information, I would want to basically use the three-year time horizon and look at the specifics.

MR. FRANKLIN: That's a lot of contract information that has to be evaluated.

MR. PACE: Right. I'm suggesting to you that you can't do the analysis that way. The Staff paper doesn't envision doing the analysis that way, I don't think. Yes, for the applicant, you could ask the applicant to tell you with absolute certainty what the status of its load and obligations and contracts is so you can understand what its position is. But then the poor applicant standing there has the problem of saying well, my goodness, how do I figure out what other capacity in the market is uncommitted.

And what your paper describes, which I would agree with, is you take a shorthand approach: let's take the first tier example. You look at the first tier control area and you look at the total capacity that is there and the total load that is to do that, taking up reserves and taking out outage and allowance for outages and adding operating reserves and you treat whatever is left on there as uncommitted capacity. You are not engaging in specific matching of contracts and loads in that market.

In general, I would do the same thing in the rest of my own control area. In my control area as a whole, hopefully, I know the load and the total resources that are in there and I subtract out my bit of it. Then I know what the sort of net position of the remainder of the control area is. That's what I'm suggesting.

I agree with you completely. You cannot have a test if your test requires people in today's world to go out and line up against individual contracts, against individual obligations. We're dead.

MR. FRANKLIN: Not in 60 days.

MR. PACE: Although as a consultant, I think I could come to like that.

(Laughter.)

MR. FRANKLIN: You kind of answered the PPA, but the load flow database --

MR. PACE: I think my answer to this -- I believe my answer to this in the first instance is I want to tell the people who already do the reporting of TTCs and ATCs to give me sufficient data that I know how to use them. I'm not suggesting that I want to get inside of how they bid on the load flow studies and power flow studies and what they're doing. But you are already posting certain information, even in MISO. MISO says you can figure out what the available transfer capability from control area to control area is using what they call their scenario analyzer.

What I want you to do is put all the cards face up. In other words, if you've told me total transfer capability is 3,000 megawatts, tell me about any of that that's not available realistically through scheduling; just report another two or three line items right under that that tell me what's not available.

On the other hand, if you want to take the position I don't want a report total, as far as I know, there's no other way to use the MISO data to get a total transfer capability number. You can get an available one, in theory. If they know what's available, they have to know what schedules they have already recognized to get to

that figure and I want to be telling you that.
MR. FRANKLIN: Would that be for public consumption?
MR. PACE: I don't need to know the names, dates, and serial numbers. I just need to know --
MR. FRANKLIN: Whether there was another applicant or not that had it.
MR. PACE: I agree with the comments that have been made here. We're trying to capture the transfer capability competitors can use. If the applicant is using that up, it's not a very good competitor. You always want to take the applicant's use out of the measure at the end. That would be my answer. I don't know whether we'd do the load flow studies or get into the details. I want them to report enough information that the poor practitioner like myself can use what we've got.
MR. HUNGER: Yesterday, Mike Wroblewski of the FTC argued that in order to properly define the relevant geographic market you would have to look at market price, then the operating costs of both applicants and competing suppliers. I've got two questions: One, what do you think? Do you agree with that? What do you think of that? And two, what data issues would that bring up for us if we went down that route?
MR. PACE: Let me give a couple of answers to

that. In theory, for a definitive test of market power, of course, that's true. For a definitive test of market power, you've got to bring all the economics of supply and demand in. That would be the delivered price test and probably the delivered price test isn't good enough even to capture everything that needs to be captured.

I would argue you can't go there if you want to go to an analysis that's that complicated and complete. Forget a screen; we're not talking about a screen anymore. We're talking about requiring a definitive analysis of market power before anybody can charge market-based rates. I don't think you want to go there.

MR. HUNGER: There's something to be said for a definitive analysis of market power before you give somebody market-based rates.

MR. PACE: The problem I have with that is the alternative is not good. The alternative is throwing the competition baby out and substituting regulation, regulated rates. I would hate to see us just pick a test that drives everybody back to the regulated rate regime again.

MR. HUNGER: Why would that drive people back to regulated rates, because it's too expensive or too time-consuming to do a test?

MR. PACE: What I mean is if you put up a test that in effect says you've got to go through a merger-type proceeding or worse to get market-based rates, that's pretty onerous. You may just find a lot of people withdrawing from the market.

But again, I think the objective -- what I think the Commission has been searching for is to find a screen. A screen is, by definition, is a simplification. You must set the threshold fairly high. You don't want the screen to be real easy to pass, you want to be able to have a fairly strong presumption that when somebody passes the threshold of the screen they in fact don't have a market power problem. But nevertheless, you've got to simplify the thing.

MR. BARDEE: What if we had a scheme that said we're going to adopt a screen, whatever the screen may be, and give the applicant an option of also filing something like a delivered price test. I assume if we arranged it that way that those who passed the screen would stop right there and those who knew their numbers weren't going to get them past the screen could, in their initial filing, including the delivered price test.

MR. PACE: That's a way to go if you set a sensible screen analysis. What I'd hate to see you do is set a screen -- and that's the point I had on the point of ignoring native load. If you have a measurement issue, don't pretend it's 0, which is -- a lot of people on the panel have urged you to do in the last couple of days. I think it would be unfortunate just to set up a screen analysis where we can predict to an absolute certainty that the seven largest utilities in the country are going to fail that and there's nothing they can do about it. And they just then have to move on to a delivered price analysis until somebody decides that's not good enough either.

MR. BARDEE: If we set up an appropriate screen, a reasonable screen, you think that might be a useful option to give applicants?

MR. PACE: Yes. In fact, I think that's what you do want. If you set up a reasonable screen, I would encourage you -- you always want to make an opportunity for the applicant to come in and not to just the word "pejoratively," but to tell you a story as to why there's not a market power problem and they don't have a problem despite what that screen analysis showed you. There could be lots of ways to do that; delivered price analysis could be one of them.

MR. LARCAMP: If someone is here for a merger already where you have a delivered price test, is that an appropriate time for us to reconsider generation market power? The merger eliminates a competitor. It may be a contiguous merger. I mean, it depends.

MR. PACE: Basically, I think the answer to that is yes. It seems to me no matter how you look at it that's a material change in the market situation that led you to give the market-based rates in the first place and it ought to be re-examined at that point.

MR. O'NEILL: Joe, one of the things you mentioned, I guess, was a simple screen for the people who really don't have any market power. I think that's an important issue. And if you have any more thoughts on it, I think that would be very helpful because the Staff obviously is looking possibly to increased burdens on the big utilities. And for small independent power producers, something -- maybe even to the point of rebuttable presumption --

MR. PACE: I think that's the term I used in my written comments. Again, I think anything you do is arbitrary but it just strikes me that if you were to set a threshold as low as 10% -- and the 10% remember as I suggested is 10% of the capacity physically located in the area -- you've ignored import capability for the market share is even lower. It just seems to me that ought to be a free pass home without considering anything else.

I would also apply that free pass not just to the little guy but to the large utility who essentially has no presence in adjacent control areas either. It has been, by and large, in my opinion, a waste of time to have to look at first tier markets in most of the market analyses for investor-owned utilities --

MR. BARDEE: In terms of a free pass type of analysis like you've suggested, you've described, this is a market share without a pivotal element to it. Do you think adding that, but still leaving out the import element, would be appropriate?

MR. PACE: My instinct was if you get down to that kind of market share, forget the pivotal. Again, I would really look for a way that people could just give you a real quickie filing -- and again I'm thinking of all these poor independents who've got generation scattered over all these 15 control areas and just have them be able to come in and say Here's the total capabilities in those areas, here's mine, I don't exceed 10% of the market, I'm done.

MR. BARDEE: In a really tight market, having 10% is certainly enough to push up market price.

MR. PACE: It's 10% completely ignoring import capability; it's not really 10%. Again, you're never going to get a screen analysis so high that there can't be any possibility of this. It struck me that that was a very sensible balance and I'm sure, in fact, a lot of my clients would criticize me by saying 10% is insanely low, but that was what was suggested.

CHAIRMAN WOOD: Joe, how does that punch up against your suggestion that you back out the native load? Because the 10% snapshot would include all the native load generation, too. If you really backed out the native load, as you urged yesterday, the 10% may well be 30- or 40% of what's left over.

I think, to build on Mike's point, that may actually be a concern that even with imports and what have you, they maintain a significant amount of the percent -- of whatever uncommitted capacity, I guess is what you called it yesterday, that is used when you back out the firm load. I mean, the simplification is seductive but is it really being honest with kind of the approach that you guys were advocating yesterday?

MR. PACE: Again, I'm not going to contend that you could never have a problem. But what I was trying to pick was some number that could get down low enough that we could just view it as a no-brainer without having to worry about anybody else's capacity numbers or imports. I mean, that's something I really encourage you to try to do, is find some way to give a free pass to the small market players, that one would really have to stretch the imagination to think that they're the source of the problem.

CHAIRMAN WOOD: How high has that been in the last two years that we've been doing the SMAs? Is everybody filing a great, big expensive study?

MR. PACE: This is just a way of making it easier.

The other alternative to that is that most of these guys presumably could pass in all but extreme circumstances. But to do that, they've got to go out and do the transmission calculations and so forth.

The other thing I didn't mention that one way you can simplify -- always encouraging you to allow an applicant to simplify, adopt conservative simplification anytime. In other words, if an applicant says well I don't have good information on the amount of import capability, I'll assume it's zero, and even if I assume it's zero I still pass -- or I don't have good information on amount of uncommitted capacity, particularly in a municipally-owned neighboring area, okay, I'll assume it's zero, I can still pass. You certainly ought to encourage that.

MR. RODGERS: Dr. Pace, you mentioned earlier that if an applicant is using ATC they should identify -- or we should require them to identify the actual transactions that take place. Is that something the Commission could implement right away for someone who wants to come in for market-based rates, tell them that if you want to use ATC or we direct you to use ATC, we need to identify the actual transactions that took place at that time?

MR. PACE: A slight correction to that: it's not necessarily the applicant who has that information. It's whoever is posting the ATC on OASIS. Whoever has the responsibility for posting ATC, I'm prepared to assert as a matter of logic, must know the transactions that have been scheduled to eat up the capacity and get them down to that ATC number. All I want them to do is to tell me what that number is. I'm not really an expert on how you would go about telling them to do that, but it seems to me that that's some kind of an amendment of the posting regulations for OASIS.

MR. RODGERS: You also suggested earlier that the Commission could require those who file Form 714s to identify who is in the load that's reported. I'm wondering if that might be perceived as burdensome on some who filed 714s. Do you have any feel for that?

MR. PACE: I don't see why. The fellow who is measuring the total load ought to know what he's got in it, although I will tell you that I've had the experience of lots of questions taking a long time for them to figure that out. They shouldn't have to wait for litigation to do that. My recollection is that the 714 says you're supposed to include full requirements customers. I believe there's actually a page where you're supposed to list them. That page doesn't show up electronically.

But the other issue I've run into is if the person says Yes, I include partial requirements customers in my load, what is he including? If the partial requirements customer has got a load of 300 and they need 200 of it themselves, is the person doing the reporting include the 100 he is responsible for, or, in my experience, many times he's including the whole 300-megawatt load because that's the way he thinks about life. He thinks about the other guy's 200 megawatts of resources as a way to meet that, but the whole 300 megawatts is in there. And a lot of the control areas we look at, it can be hundreds or even thousands of megawatts of that kind of load around. You need to know what's in it.

MR. RODGERS: Does that suggest that the reporting to you in Form 714 is inconsistent, that some people may be reporting it one way and some another?

MR. PACE: I'm pretty confident that based on my experience, yes.

MR. RODGERS: Why don't we move on to our next panelist in the interest of time, if we could?

Thank you very much, Dr. Pace, we appreciate that.

Our next panelist is Seaborn Adamson, Director of Tabors, Caramoni and Associates. He has provided consulting services for Conectiv, Dynegy, independent power producers.

We're glad to have you with us here today, Mr. Adamson.

MR. ADAMSON: Thank you, Steve.

Continuing the trend established by Bill Hieronymus earlier, I'll start by declaring my kind of interest. I did the work for a whole range of clients, utilities, marketers, and generators. However, what you're hearing from me today is very much my own opinion here today. None of my clients may be happy with what I'm going to say but it shouldn't be attributed to anyone else but me.

In acquiring these types of market power tests, I think we kind of need three things: we need a solution concept such as the pivotal concept at the heart of the SMA test, we need a methodology in order to kind of implement it, and then we need the data necessary to it.

I'm going to talk mainly about some of the data questions. I'm going to talk a little bit about the kind of concept that we're going to supply because that does define a lot of the data we need. The SMA as it has been implemented. This is a very simple test. It's economically pretty much a test for a single dominant monopoly, somebody who you think will always withhold at the peak hour. In that it's not really realistic. It overstates market power by only looking at the peak period, assumes everybody has perfect information so they always would know how to do this. It ignores people contractual obligations and so forth.

It also understates market power in a lot of ways. It looks only at the exercise of pure monopoly power as a pure unilateral strategy and I think we can all perceive that multilateral strategies, oligopoly strategies can be important in these markets.

So it has quite a lot of weaknesses as a test. It's neither too conservative in all the cases nor too liberal in all cases. It can kind of switch both ways. The difficulty is what it wants to do.

There are other methodologies that have already been used, the price test Dr. Pace described. I would encourage you, in terms of thinking about what else might be considered to think about some of the techniques that have been used outside the United States, where jurisdictions have not had a single way that you're obligated to do this because I've developed very interesting and comprehensive game theoretic techniques for looking at these things in electricity markets.

These have been applied in Alberta, in Canada, Europe, and Australia. They allow you to capture a lot of the significant interactions people have discussed here in the last two days.

Although having performed one or two of those studies and certainly having reviewed a bunch of other ones, I offer the caveat that they do not offer the type of bright line type test that an SMA test does. That's not just because they are done by people who didn't know what they were doing or whatever, it really does come down to fundamental economics, which is to say that these analyses are usually based on application of the Nash equilibrium and one thing we know as economists in market is, where there is one Nash equilibrium, there are often lots.

How do you decide which one you are going to pick? You can't necessarily get to a single definitive answer like you can with something with the SMA, although you can capture things that no SMA-type test can capture. So, back to the world of the practical and the data necessary to apply it.

First, before I go on in my mind I think I would like to agree with the previous two speakers. These types of tests can really only be indicative tests. It is not possible in my mind to define a determinate test that can relatively usually be applied and I in general support the ideas advanced by Dr. Pace that we need to get a way to get most of these people out of getting beyond a very initial analysis very quickly.

I think all of us have seen or filed or whatever screening tests for people who have 184 megawatts plant stuck somewhere in the middle of Oklahoma, and you're thinking, they're going to pass any conceivable test.

Surely, there must be some way to avoid them having to go through this process and also to eliminate some of the burden on Commission staff in reviewing a bunch of these materials.

So I very much support the idea of having some form of relatively quick, check-the-box test.

I also support the idea, and it's something I've used before, and that Dr. Pace also noted the idea that if you can get people who are often going to be pretty easy passers, to figure out a way to do it with very conservative assumptions that don't need a lot of information about it.

If you are going to pass with a zero percentage import assumption, write that at the start. Put that in there, check the box and say, we want everything with zero import, we still pass by lots, click, let's go.

I can't imagine that that doesn't make FERC staff's obligations in reviewing these studies to be easier. Now, for those who aren't in any kind of pass, the kind of quick check-the-box type test, what do we do?

For now, I have not come up with a method that I think meets a require for easy applicability any better than some probably slight modifications to the SMA test, many of which have already been discussed by the previous speakers. I do, however, support the idea for the kind of big cases and critical cases that people should be able to offer additional analysis or that the opponents of such applications should be able to offer additional analysis that does more realistically capture the realities of the power system and the supply characteristics in the region in terms of what I think would be a relatively limited number of kind of "tricky" cases. What do those have to do with?

We already talked about the ATC and the TTC thing. I think that's the biggest one in my mind. Also, particularly very much looking at some of these control areas, which after all, are pretty big. Some of them, where you have transmission constraints within the regions, you know, went out looking at those transmission constraints, or potentially without even looking for some systems, without looking for transmission constraints that are not necessarily on the ties that may be constrainable interfaces elsewhere on the system.

You are going to get the market definition wrong and you're going to get a nonsensical type analysis with regard to specific data for most of these issues.

I would agree with Dr. Pace that for most of this data, there is stuff out there that is usable to the level of approximation that we probably need. There certainly can be problems with this low data in and out. This strikes me as something that would be relatively easy to clear up, if directed by the staff.

I definitely support the ability to use generic gaps type outage rates type data. The big question I think that is very difficult to apply, is really the data on the transmission side and that's where it's much harder for people to start making reasonable assumptions without paying someone to start doing huge load flow studies, which even then would be questioned.

As we move on, we move to sort of deliver the price-type studies, as Mr. Hunger pointed out. We are going to need cost information as well as kind of just quantity type information.

We were looking at deliverable, competitive resources within some sort of cost-type bound. I guess my experience is, as someone who does a lot of modeling in these markets, is that there is actually reasonable databases you could use out there. You do have to pay for it. It's not available necessarily from any single source. It's certainly not all available from one set of filings to the FERC.

You have to assemble quite a lot of it. It's very costly. It's very difficult to check and to the extent that people do rely on that type of data, you certainly will need to get a process. These days, it requires that people will be able to question that data.

Part of our experience in doing lots and lots of transmission and generation system modeling is that an awful lot of the public domain data out there has numerous data problems and correcting it is extremely time intensive.

In summary, I think the data is generally out there largely for what we need to do and our transmission data is the biggest question. SMA is probably okay. It's a reasonable screen. I would support a much simpler screen for the really small guys and I would suggest looking at more sophisticated measures for the real borderline type questions. Thank you.

MR. RODGERS: Thank you Mr. Adamson. I had a question for you as well as Dr. Pace, and possibly you as well, Mr. Frame.

I know that Dr. Pace and Mr. Adamson have done consultant work in market power analyses for both clients that had transmission information, network control area operators but also for those that were not. I'm wondering, if in your experience, is there a great disparity between the kinds of data that you have access to, working say for an IOU, versus working say for an IPP?

MR. PACE: I think the only disparity that I can think of we're going to go to OASIS to get your transmission information generally. The only other disparity is, I found in some cases that the utility seems to have a little bit more capability using its own internal transmission guides to help fill the holes and run some other studies for you.

It obviously depends on the size of the independent but they have that capability. The other thing is, I think, that the typical incumbent control area utility, they've got people that have probably a much deeper understanding of any potential local transmission constraints and issues than any just ordinary market participant is likely to have.

MR. RODGERS: These transmission studies that are done by folks that are in-house for the IOUs, is that using publicly available data of is typically using data that just a transmission owner would have?

MR. PACE: The ones I have in mind usually use a base case load flow study. It's "publicly available" in the sense that it's available to more than just them. It would probably available to the significant market participant but it's not available to me as Joe Doakes, but it is used by the reliability council of the area therein.

One other thing I was mentioning, it has been my experience that any study in the end is tempered by a little judgment as to what do you do about itty, bitty local constraints that sometimes pop up for a short period of time. Do you really count those things in limiting the capability and so forth?

The transmission people that are on the ground dealing with that system all the time know more about that than anybody else.

MR. RODGERS: Would you like to comment on those questions Mr. Adamson?

MR. ADAMSON: A little bit. My experience is probably most of the information is kind of out there somewhere. The significant advantage is being able to get it in some form of accumulative manner rather than trying to assemble it and cross check it and understand the assumptions built into these.

You've got these base case load flows which is this huge file, then you've got to figure out well, what's exactly in it. It's a bit like what Dr. Pace was pointing out. Even with the 714s there is stuff built into that. You have to understand what's in it and what it actually quite corresponds to and all that type of stuff.

Probably the advantage I assume that the transmission guys can provide you in a very kind of much more convenient fashion. That stuff is very time-consuming to put together if you are an outsider trying to put it together and trying to prepare something, you really need to say, get into that kind of load flow type analysis. It's really time-consuming and very expensive to put together.

MR. RODGERS: One other question I had for you Mr. Adamson. You suggested that if there was one area where the Commission could help in the gathering of more information or require the gathering of more information, it would be in the transmission area.

I'm wondering if the kind of transmission data that you are suggestion the Commission could require transmission owners to provide either to the Commission or the public, might be the kind of data that could be considered critical infrastructure information they might not want to divulge or it might not be appropriate that they divulge that information for that reason. Do you have a feel for that?

MR. ADAMSON: Not really because I'm not sure that I'm au fait enough with what exactly falls under critical energy infrastructure information other than seeing that stamped on things. So I don't know that I'm appropriate to speak to the merits on that.

MR. RODGERS: Any other panelists feel comfortable in addressing that?

MR. FRAME: It's never been a problem in anything I've ever needed.

MR. PACE: I have heard some of our fellow consultants in the engineering business say that they find this a problem.

MR. RODGERS: That they find what a problem?

MR. PACE: The kind of broadly defined national security interest. Some of their reluctance that people are much more reluctant to make available to outside transmission consultant guys the full array of transmission studies that they would have been able to get routinely two or three years ago. It's somewhat of a problem I think. But again, my understanding generally is, as long as you are a market participant, you have a way to sort of get in and get it I think.

MR. RODGERS: Thank you.

MR. SINGH: Steve, you mentioned the importance of transmission given that transmission constraints can bind in parts of the year and not in other parts of the year. Would that make any peak analysis rather course?

MR. ADAMSON: Definitely it will. If you -- it's actually not that uncommon to have periods where the big binding transmission constraints are actually in times when there are significant flows which are not at the peak periods where virtually everything may be running. It's times when you're often may be trying to import tremendous amounts of available kind of economy energy, for lack of a better term, from a neighboring region.

This I guess is one of these pure trade-off things, how far do you want to kind of go in requiring a kind of off peak, peak season, non-peak season type analysis in these things and the kind of graduations therein.

I kind of like the idea of saying potentially, here is the peak and if you are going to have any other kind of number, pick some kind of percentile and say you have to do it at peak and you have to do something else perhaps at some percentage of peak loads.

It's hard to do that. It's kind of a pivotal analysis. That's quite difficult to do. You'll probably find that it may not be a particularly meaningful type of thing if you're going down to a straight pivotal type analysis. Certainly if you went into the next round of doing any type of deliberate type pricing you should definitely not just look at peak periods.

MR. SINGH: Also you eluded to the fact that the test focuses on monopolistic behavior. The implication being that it ignores monopsony power.

MR. ADAMSON: First off beyond the pure monopoly issue, on the supplier side, I notice there is the possibility of non-pure unilateral type action. I do think these markets are developing and they are developing quite quickly in some ways and they are developing in a lot of ways that I think are quite different from how we all envisioned that they would be operating several years ago.

We will gradually be turning our attention, more and more, all of us toward vertical market power issues rather than so many horizontal market power issues. Those are common obviously in other areas of antitrust. I think we are going to be looking at markets that are going to be more and more dominated, at least for the short term by longer-term type transactions.

Without significant retail competition, the competitive landscape at the wholesale level is going to be largely defined around RFP-type decisions and I think there, the Commission's role in terms of affiliate relationships and this type of vertical market power issue is going to be increasingly important in any kind of potential for price discrimination of paying one set of people one thing and one set of people the other thing. I think that's really going to turn out to be one of the most significant issues going forward.

I haven't really talked about that too much because I have tried to focus more specifically on the data issues regarding implementation of these tests. But over the long term, vertical issues in market power tend to get as much attention as horizontal ones.

MR. SINGH: One final clarification of the ATC versus TTC discussion we had earlier. Wouldn't it be better not just to see how much of the capacity is already reserved for someone but also what the usage has been because I think the concern there is primarily hording if one of the applicants in the control area has reserved that and doesn't use it, then it should not be counted.

So you would essentially take up the suggestion that it is important to get actually some usage patterns off that capacity rather than just a listing of the TTC is 2,000, the ATC is 500 and 1,500 is taken by someone. It's important to get the breakdown and then also flow patterns and whether or not it was actually used.

MR. ADAMSON: If that's a possibility and if the release rules aren't going to prevent that, that's definitely an issue. The worst possible situation is where you have something where somebody has had the ability to lock up a lot of the transmission capacity and then not use it. That's clearly exacerbating the market power and the constraint issue, I should think.

MR. RODGERS: Thank you very much, Mr. Adamson. We appreciate your comments today. Moving on to our next panelist, William Townsend, the Senior Director of Database and Spacial Information with Platt's Energy Information and Training Services. Welcome Mr. Townsend.

MR. TOWNSEND: Thank you very much. I appreciate your opportunity to address the Commission and the staff here today. I am encouraged by the comments I've heard so far from my co-panelists. They seem to be very practical and sensible comments. I apologize if I reiterate some of the comments but hopefully that will just reinforce some of them.

At Platt's, I'm mostly responsible for the data collection and aggregation and delivery of information services to various industry stakeholders, regulators, energy companies, ISOs, other entities. Consulting firms that support these types of market analysis. We're probably one of the primary data providers that collect information that the Commission collects, EIA, NERC, EPA and disseminate that broadly for use in these types of analyses.

I'm going to probably keep my comments focused on the specific data, the quality issues that we believe are in the more definitional issues and areas where there maybe some ways we can improve that data together to address these issues or at least to be more aware of the error in that information when we're making decisions based on conclusions reached using this type of information.

To me it sounds like the basic types of information used in this analysis at the first level are load capacity and the OASIS data. I'm going to try and address each one of those and then if you like, we can discuss data issues that come if you end doing a load flow or a market assimilation analysis which has some additional data sets necessary to perform on the load side.

The data source that's most often referred to here is the FERC 714 filing which includes, I believe, it's the entity defined as the planning area load, it's hourly load. There are a couple of issues with this. One is the definition of what's contained in that load, and Dr. Pace discussed which requirement loads are included in that or not.

There is a page in there that's part of a hard copy filing that does define certain requirement loads that are included in there but there are still issues of overlap. If you add up those across a region, for example, the WSCC, the total of those 714 entities would actually add up to a greater number than you would see from a NERC assessment.

So you've got some overlap. We've got some double reporting going on in other areas, it ends up short of what you'd expect from a NERC assessment. What we do is we try and cross-reference these things from multiple sources to understand where there maybe issues, either data omissions, data redundancy or measurement error.

The other issue with the load data is, that there is a timeline for all this information and I believe right now the most current data available for assessing hourly loads across the board in all market areas is 2002 data, so you're looking at data with a substantial lag in terms of performing this analysis.

That can be also said that with the capacity data, the frequency of reporting by the reporting entities and publishing by the regulatory entities that collect and retain those data sets, introduce some errors themselves because obviously there is demand growth. There is load lost in some areas due to macroeconomic changes.

These things aren't necessarily reflected in data that is available to do the analysis now. So frequency of reporting, I know there is an additional reporting burden for those things but we see a gross difference between a more liquid functioning ISO market where we are actually getting load in real time, and then at the end of the day, for settlement purposes, and possible through and up at the end of the month versus an area where we may have to wait six months to a year and a half to get good load data on.

So, determining if we can improve the timeliness of data to reflect more current market conditions is important.

The other issue is, are you just using the latest load data is then a representative of conditions going into the future. Was it an anomalous whether here, should we be looking at averages or some type of projected load to do these assessments are important considerations.

On the capacity side, likewise there is multiple sources of capacity information, whether it's reported annually as part of the FERC Form 1, as part of the generating unit file, as part of the NERC filings for seasonal ratings.

If we're looking at a winter peaking market versus a summer peaking market, should we be looking at the seasonal ratings and the differences there in terms of the total capacity of the market?

Then lastly, outage information. If we're looking at a peak period analysis, there is really probably hardly any planned outages expected, so you need to look at an expectation of forced outages and the data available on there using estimates that are based on GADs reporting data or historical things may not be a good indication of what's going to happen in the future.

Probably the biggest data issue though, comes with the transmission data. This open up a lot of questions about the TTC and how to use the ATC data. I've worked with this data on a very intimate level for about the last three years. There is a great inconsistency across many of the different transmission operators. They all make strong efforts to make that data available and to serve their customers, the transmission customers, but we still see a lot of inconsistencies.

Whether it's simple inconsistencies of some nodes developing the 1.3 standard versus the 1.4 as to how they report their ATC capacity. Then there is the ongoing issues of some issues updating their agency more frequently and keeping that data alive and reflective of true conditions. Then there is simply the definition of paths and points of receipt and delivery.

We're somewhere around six years into using OASIS and, if that's correct and we still have issues about seams. Those all add up to how do we use this information. We've been an aggregator of that information since about 2000 and we struggle quite frankly each day to serve our customers in maintaining a complete warehouse of that, just simply accessing each node and requesting all data the data to be able to depict both the long and short term markets.

So there is just a technical difficulty in obtaining the data to perform any analysis or actually conduct your operations.

Furthermore, I think there was one issue about the question of using ATC or TTC. The other side of the OASIS data is the transmission reservations. That data is available to look at. There is a data set, a status template in OASIS which allows you to see which reservations have been made, when they have been made, what parties have made them and over which paths.

There is the ability to use that as part of a screen analysis, but again, the same issues do prevail. I believe that data to be somewhat higher quality than the ATC and TTC because it reflects the need to actually schedule the operations and the capacity of the power flows. Getting it wrong is a much higher consequence for a transmission operator than the ATC numbers.

I think the real interesting things here are, is there a way that we can either indicate the errors in these data so when you're making your assessments or using your screen that you understand whether the applicant indicates whether there is a bias upwards or downwards, whether these types of errors in the analysis are additive or not.

I think that's especially the case if we were to address a simulation tool like a dispatch model or a load fill model that's dependent on things like unit cost of production assume fuel prices for variable operating costs.

If we are making assumptions on many units that no longer disclose those costs, there can be a tendency to bias upward or downward and that's an additive thing if you assume that a certain gas plant has a certain variable O&M cost of let's say $2 or $3 for megawatt hour. If you're biased with that assumption, it's going to move your entire supply curve and shift it to the right or to the left, depending on your bias.

These are sort of important considerations because the data has these problems in consistency and built-in error. I think it's fair to ask the applicant to address that in their filings and to discuss those data issues and which way the error may be influencing the screening analysis.

It also argues that this type of screening should be indicative and perhaps there are several types of screens that could be used in conjunction to come to a more fair assessment for the applicant.

That's pretty much everything I had to address. I will take any questions if you have any.

MR. PEDERSON: Mr. Townsend, you mentioned earlier about the inconsistencies in Form 714 and you mentioned that you guys cross-reference from other sources. What are those other sources? Are they publicly available? What are they?

MR. TOWNSEND: All the data we're talking about is publicly available. As part of annual filings there are monthly peaks that are filed. I believe there is a schedule on the FERC Form One, the EIA 412 and the RUS forms that shows monthly peaks for the specific energy companies, so we cross-reference that.

We also try and aggregate them and look at the assessment reports that come out from NERC as well as the EIA 411 report. On load data, to my knowledge at this time, and there maybe some additional miscellaneous sources that we also look at.

MR. PEDERSON: Also, with the TTC and the ATC, the inconsistencies there on how the utilities are reporting those and how do you deal with those.

MR. TOWNSEND: It's difficult. A lot of our customers are looking at issues like you are for public policy but probably the prevailing majority of them are either doing actual trading and operations activities on a day-to-day in the short-term market or business decisions, or the most vocal on the folks operating in the short-term market. They are actually trying to make the reservations based on ATC information.

What we do with them is try to indicate the level of quality and confidence that we have from a specific provider in those numbers. We also try to make it very transparent. When was the last time that particular number was updated with an update time, when was the last time we've checked that number to make sure they know we're frequently looking for that data.

But in a lot of ways, it's beyond our control. The other way we can depict it to some extent is to add up the reservations and show what is the total sum of the reservations on that path for the time you're looking for.

That's sort of an A + B = C or C - A = B sort of an analysis looking at it from as many ways as possible to get a sense of what the available transmission capability is. The problem comes with not having a transparent way for the transmission provider to communicate how ATC is decrementive on one path when another path is reserved.

It gets to these issues we've discussed here with either a scenario analyzer type thing that the Midwest ISO and SPP provide which feels like a black box to a market participant. You type in your source sink and type in the amount of capacity and it just says yes or no. It's a little difficult to address issues like the ones we're talking about today or even distant planning issues over a longer horizon with that type of tool.

I believe however, that the transmission providers are trying to provide the most realistic way of whether or not your transaction is feasible, but it's not necessarily transparent. That varies greatly across different regions. We've had, as a service provider to this industry, to sort of take that as a given and try to add value around that, and it's been quite a challenge in the transmission area.

MR. RODGERS: Which regions do you think have the most transparent data in your view?

MR. TOWNSEND: Which type of data, the OASIS-type data?

MR. RODGERS: Yes.

MR. TOWNSEND: The ISOs are doing a very good job, but they actually have a much more simplified model now. Internally they are dealing with their LMP models and there is only a few paths in and out of them. PJM, New York, and New England are doing a very good job in maintaining the short-term ATC and TTC numbers and disclosing even physical flow data to market participants so they can validate those numbers against what's actually happening physically on the grid.

I think, depending on the different markets, some markets have a greater need for short-term data than long-term data because of liquidity in the markets and it's hard to say whether it's sort of a chicken and egg thing. If they had greater transparency regarding ATC would that help liquidity in the market or not, or if there is no liquidity, there is not a great need for that data. I can't really say but I can say that there is a big sort of regime change going from the ISO market south, where you tend to have very standardized point-to-point, pretty readily available data, and as you move west, getting into the regions like the Midwest ISO and SPP that work more often than interchange distribution calculator or flow gate model, it becomes more difficult to assess what the ATCs are.

At least in the short-term market, they usually post longer term stuff, but it just becomes more difficult to sort of match up what's the market extent and where are the boundaries, and what are the paths into and out of that market.

MR. RODGERS: So in terms of the accessibility of data, the timeliness of data, the accuracy of data, from what you can perceive, the best job people are doing with that is in the ISO markets then as you move out west, it's not as good.

MR. TOWNSEND: It's more difficult to put it all together across the regions. Within each region, it's fairly consistent but trying to deal, if you define the market, as let's say the Midwest ISO and MAPP, looking at how it interacts with the neighboring ones, becomes pretty difficult.

MR. RODGERS: The Commission has traditionally used control areas as the relevant geographic market in its market power analyses, at least for market based rate purposes. I'm wondering if we went to a larger geographic market, do you think there would be data that would be as readily available and would be as accurate.

MR. TOWNSEND: I think it's worth doing the exercise if you keep the screening in a simple fashion, the way it's been proposed here, to do it at several levels of analysis, perhaps as small as a control area and then at the next level that the data becomes available, perhaps at the NERC subregion and the NERC region level and compare those and contrast them.

I would envision you could also combine a delivered price analysis, looking at market price indexes at those various price levels, looking to see whether or not the spreads between those markets at peak times or off-peak times actually have any meaning.

You'd like to think that transmission constraints and price spread are related things, but there is an arbitrage condition that people are trying to take advantage of.

I would encourage you, if you are going to do that sort of thing, to look at the prices as well. I don't know exactly where that threshold would be though, that would be something that would be arguable.

MR. FRANKLIN: Bill, just a little disclaimer. We here at FERC have RDI and Platt's is the vendor for that so I've actually talked to him before, he's helped me with queries, but one question I wanted to have you address, is the issue of internal constraints.

I know from just your previous statement that you have OASIS data for the control areas, the bordering tie lines around control areas, and the bordering tie lines around subregions, but is there anything that you are aware of, either within your company or other companies, from any public vendor that could supply information on load pockets.

For example in ECAR, they have load pockets, they have Pittsburgh, Cincinnati as an example I brought up yesterday. A lot of times, there is congestion in those load pockets, even though overall, the system looks fine.

From an aggregated point of view, are you aware of any place you can get either simultaneous input capability or even for that matter, individual tie lines?

MR. TOWNSEND: There is probably two sources of data that do an inadequate job on that. Some is some of the flied-wired data, which is basically aggregating all of the tie flows or flow gate flows from the FERC, the various ISO, some NERC security coordinators make data available on key constraint points, whether they are inter ties or internal, but it's sort of a catch-as catch-can. It's very spotty from region-to-region, and it doesn't necessarily allow conclusive analysis that there is a load pocket there that's been constrained.

It's sort of like there is an equation with eight variables and we can only have measurements for five and we don't have the ability to estimate the other three. That could be rectified by rate of disclosure of certain types of data that have been discussed. Either additional flow gate data so a greater proliferation of distribution of that information.

MR. FRANKLIN: Through OASIS?

MR. TOWNSEND: It could be through OASIS, it could be through the security coordinator. There are various mechanisms that that could happen and it certainly been growing over the past few years in terms of the disclosure within the industry of that data.

It has been argued that that's fairly sensitive data through in terms of critical energy infrastructure information. It is physical power flows real time over very important, very large tie lines. So, greater distribution of that, or greater availability of that might help identify those pockets that you mentioned.

Greater disclosure of things like frequency or ACE data within control areas maybe a way to get at that. There might be too high a level of aggregation to really pin point when there is problems.

It's a good question. I think it's a hard question to solve from a technical standpoint. The load flow models that we're supposed to discuss before can represent those things. The problem is, they have so many assumptions built in on the BUS level, demand and generation, which may not necessarily reflect economic reality, even if they model the physical attributes of the system very well, they may not necessarily represent the economic reality of it.

It's a tough question. I would almost step back from that and say it's almost looking at too much of an issue, perhaps the broader screens and coming up with multiple broad screens like we're talking about, might be a more effective way of looking at these things rather than diving into the minutiae of the load flow model or looking at real time power flows at several thousand points. But there is some availability of that data and you may be able to perform that analysis in some markets using current data, but not all.

MR. RODGERS: Thank you very much Mr. Townsend, we very much appreciate your helpful comments there, gives us a lot to think about. Why don't we move along to our final panelist, Steve Schleimer, Director of Market and Regulatory Affairs for the Calpine Corporation.

MR. SCHLEIMER: Commissioners, Kelliher, staff. Thank you very much. My name is Steve Schleimer, Director of Market and Regulatory Affairs for Calpine. We appreciate the opportunity to address these important issues. I'm very happy to be on the data and miscellaneous issues panel.

I'm not going to say much about data, but I have more say about the miscellaneous stuff. Bear with me, and I'd also like to point out that hearing Mr. Roach this morning, I endorse just about everything that he talked about.

As you may be aware, Calpine currently has 20,000 megawatts of generation online. We expect another 10,000 megawatts to come around in the next couple of years. We are in 22 states, we are the largest non-utility renewable provider in the country.

Why are we here today, other than the fact that you invited us? We build generation infrastructure, and we bring value to consumers by building it cheaper, faster, cleaner, and with less risk to consumers and to our competitors, including the incumbent utilities.

We're here to advocate eliminating existing preferences and hurdles that sometimes prevent the most cost-effective, efficient, and reliable generation from reaching consumers.

Taking a step back, this is what we're here all doing, delivering better, lower cost alternatives to consumers, to the interactions of many buyers and many sellers in the competitive marketplace.

The problem is in most areas, companies like ours can't sell our products directly to consumers, instead we must sell it to the utility, who goes about reselling it to the retail customers.

The main point I want to get across to you is, that while Calpine generally believes that FERC is headed in the right direction with SMA, we believe that it's a very limited tool, because it only deals with the seller's side of the equation, it doesn't address market power held by utilities that buy on behalf of their customers. As well as the fact that many of these buyers also hold residual transmission market power.

These two issues, if not addressed soon, I believe could potentially obliterate any progress we've already made in the development of comparable markets.

Since much has already been said about the transmission access issues, I'm going to focus the rest of my comments on utility procurement of energy supplies and issues related to that.

We all know the events of 2000 and 2001 and the adverse impacts on competitive electricity markets that occurred during that time period, but I'd also like to talk about 2002, 2003, where we witnessed a very disturbing and growing trend away from using competitive markets to meet consumer's needs and back to where we were 10 or more years ago with utilities own and rate basing new assets.

This comes at the same time that IPPs no longer are developing projects according to the merchant model where they financed their plant and try and find a buyer. Instead, because of what's gone on, in order to develop new generation infrastructure, you need relatively longer-term PPAs.

Over the past several years, we've seen utilities holding "competitive bidding processes" and choosing themselves to build, operate, and own their own rate based cost of service asset, or implementing what we have affectionately called, a BOT, which is where they get a third party to build the plant for them, operate it for a year or two, make sure it runs right, then transfer it over to the utility for their ownership.

In rate basing, this essentially turns what used to be IPPs in to construction contractors. We've also seen utilities holding "competitive bidding processes" and choosing non-regulated affiliates. There have been several cases of utilities attempting to transfer assets out of their unregulated merchant affiliates into utility rate base to get cost of service treatment for them, claiming that those assets were really built not to be purely merchant generators, but were built to serve local retail customers.

To finish it out, we've seen utilities choosing to not enter into long-term contracts at all, but instead buying the underlying asset at a "distressed" price. The adverse effect of this growing trend, we believe cannot be overstated.

It's effect is to eliminate competitors and to concentrate economic power in a limited number of utilities, retarding the development of truly competitive wholesale markets, which we believe harm consumers in the long term, and is contrary to the direction this Commission has been heading for years.

Calpine does believe the SMA should be implemented as promptly as possible, but if the Commission does not focus on these larger issues sooner rather than later, there is not going to be much of a wholesale market left in which to apply the SMA test. It's simply going to be utilities trading amongst themselves.

Affiliate code of conduct has been a focus for several years but what we are witnessing over the past couple of years is something different generally. There is still a lot of affiliate transactions going on. A lot of the activities are generally being undertaken within the utility themselves, and often not with an affiliate.

I believe this is because, as utility affiliates have exited the markets in many areas, the remaining utilities are viewing new rate base cost of service generation as a key growth of the traditional utility business. It's the way they think they are going to grow their earnings into the future.

In most areas, there is not yet a slit between the part of utility that buys power on behalf of the retail customers and the part of the utility that sells power, thus there is a significant barrier to entry for IPPs, even though the IPP may be able to provide a cheaper, faster, better, or better deal to customers, it cannot do so because the utility has less economic and regulatory incentive to do so.

Basically, they earn on their own rate-based asset and they don't earn on wholesale contracts, which are simply pass through. Sometimes the same utility employees, with responsibility to the generation part of the utility, are the same employees that are buying energy on behalf of their customers.

I'd like to move on to several suggestions Calpine has for mitigation of these issues. First is to implement, as Craig Roach mentioned earlier, a competitive procurement process under FERC imposed minimum guidelines and oversight.

This process has got to be free of bias and conflict of interest and it's also got to allow third parties such as Calpine and other IPPs network access to serve the utility's customers as would utilities in a self-built plant. It should also include the implementation of a code of conduct between utilities that sell power from their generation and utilities that buy power on the part of the retail customers. This code of conduct should be similar to the affiliate code of conduct.

In addition, as we've heard from previous panels, more needs to be done to make sure all competitors, utility are on the utility affiliated generation and unaffiliated generation and the like have equal footing with respect to transmission service.

And just a quick note on our thought to the SMA test, and one aspect of it. We believe the FERC should continue to use total install capacity to measure market power as pointed out in discussions yesterday, as well as today.

The incentive for utilities to favor their own unaffiliated generation, looking at committed capacity, ignores the central market power concern that merchant generators, with very small market shares, that hold the majority of uncommitted capacity, it seems crazy to say that we've got market power, because we've got a lot of generation in a certain area. But we've got no buyer that we can commit that generation to.

Let me just say in closing, that the SMA methodology may be useful in some respects for detecting supply side generation market power, it is not directly useful in addressing the utility procurement issue that in many regions is having the most detrimental effect on the wholesale market.

In order to continue the development of vigorous wholesale markets, the FERC must continue to develop policies and tools to address supply side market power, which you are doing, but it's got to increase its focus on buyer side market dominance by native load utilities in the very near future. Thank you.

MR. RODGERS: Thank you Steve. I had a couple of questions. Regarding your statement that the independent generators are increasingly finding a hard time finding sellers, that the business is sort of drying up and they are not able to make competitive sales, and the terms are getting worse and there are statistics indicating that the amount of purchased power, the amount of power flowing between regions has been growing steadily for several years, if you compare 2000 to 2001 to 2002 to 2003.

I think the numbers would show that in most parts of the country, there was more regional trading of power going on, more trading between systems. In fact, I thin that's part of the justification that's out there for why the building of new transmission is needed, high voltage transmission lines is needed because we're having these more regional trading patterns, and justification for regional market planning, oversight and indeed, some would say operations in certain parts of the country.

So, I'm wondering, how those statistics are consistent with what you're telling us, that merchant generators, IPPs, are not able to sell and the situation is getting worse.

MR. SCHLEIMER: Obviously, I'm not sure exactly what the statistics you are referring to. I'll answer it in two different parts.

One is, in certain parts of the country where there is a lot of generation that exists but because of lack of transmission access or lack of willing buyers, there is an inability to make sales even in the short term on that.

Let me also turn to the longer term, which is investment in new infrastructure. I have personally been involved in numerous RFPs, bidding processes over the last 12 months, 18 months. There has just been an explosion of them over at least across the west and I think certainly in other parts of the country.

I can say that virtually one that I know of has ended up with the utility self-built or built on transfer or something along those lines. You get sprinkled here and there, some relatively shorter term PPAs. That's what I base my assertion on.

MR. RODGERS: Most of the PPAs that you are getting are short term? They're not five, ten year deals?

MR. SCHLEIMER: No. Okay, I'd say longer. On one context they are longer term, yes, five-year, ten-year deals. Those are few and far between, but that's compared to the utility built-in rate base, the 30-year, 35-year deal, like the utilities are getting.

MR. RODGERS: For an IPP that is in a traditional market, let's say it's got a new plant, it's built the plant, it's pretty much ready to sell. Let's say it is ready to sell but it's having trouble getting interconnection or transmission service, would it be you view that kind of entity's generation should not be counted as in the market when one is doing a market power screen?

MR. SCHLEIMER: Certainly, if this is an asset that's having a very difficult time getting transmission and getting buyers, I don't see how you could count that in the market.

MR. RODGERS: Suppose it had interconnection service and transmission service approved and it's all set to go there but it did not yet have a buyer. Should that generation be counted in the market then?

MR. SCHLEIMER: I guess I would say it depends if, you know, there is an adequate reasonable procurement to process in place, and here I'm not talking about a long-term procurement process but a daily, weekly, monthly, what have you procurement process in place, where it appears that generation has a fair shot, it's actually making sales into the market, I would say yes, you want to count it.

MR. PERLMAN: Just a question relating to market power in this analysis we're talking about here. It's my understanding that if a utility does a long-term contract with an IPP that you're advocating, I assume the utility, as part of that contract, would have the right to dispense and control the operator of the IPP and effectively integrate it with its portfolio. Wouldn't that then be attributable to the utility in the calculation of whether it has market power? First of all, do you agree with that?

MR. SCHLEIMER: I heard what Craig Roach said about that this morning. It's an interesting issue because I do agree. But on the one hand, to the extent they have competitive solicitations and are truly seeking the least cost alternatives for the customers, that is an indication that this is a company that is behaving in a competitive manner.

But this issue of then, once they have a contract in hand, how do you handle that issue? I guess to the extent that they do have full dispatch rights over that, you do need to take that into account in terms of their ability to impact the spot market because obviously, they have the ability to hold back that capacity if they want to.

MR. PERLMAN: If we were to adopt that solution, would our market power solution effectively require the entity that failed the screen to expand its generation base and have continue its market power just through another vehicle, through a contract, so it's going to integrate something back into its system. And then, what do we do with respect to the market power problem that was identified in the first place?

MR. SCHLEIMER: That's a good question. Frankly, from my perspective, you know, for various reasons, I'd be less concerned, I'm personally less concerned about the utilities exercising market power in their transactions with each other, because I tend to think that a lot of times, they have long-standing relationships where that's not necessarily going to occur.

I'm more concerned exercising market power and not getting the best deal for their customers in the long run.

MR. PERLMAN: Just so I understand, your sort of vision of the competitive market is a market where the utilities do RFPs to bring in capacity to their system and the real time transactions are intermediate time transactions are among utilities because they are the entities that are trained in the new markets?

MR. SCHLEIMER: Certainly the IPPs have a role to play in the short and intermediary markets. I didn't mean to imply that.

MR. O'NEILL: Steve, what do you think the reaction of state commissions would be if we took your advise?

MR. SCHLEIMER: Of mandating competitive

processes?

MR. O'NEILL: That we oversee. Traditionally they've overseen those processes.

MR. SCHLEIMER: It depends on what state you're talking about.

MR. O'NEILL: We don't have a lot of states welcome us in with open arms.

MR. SCHLEIMER: But I do think at the end of the day, we're all here to get lower costs to customers. Certainly, in our opinion, that is the best way to do it.

MR. RODGERS: Why don't we turn to the audience now. The open mike session. Thank you very much Steve for those comments.

MR. FRAME: Are we allowed to comment?

MR. RODGERS: Go right ahead Mr. Frame.

MR. FRAME: With respect to Steve bringing up the resource planning issues, it's just not clear to me why this would be on the table now. Certainly in this contest, with respect to this panel and this technical conference, I look at this as basically a state resource planning issue. That seems to be where that ought to be taken care of.

I'm involved in a couple of proceedings here at FERC that are addressing some of the type of topics that he's brought up and I don't want to go into those, but basically you have to look at the facts and another spin to put on this sort of thing that these people haven't been successful is that they competed and they lost and the state forums have found out that other alternatives were the low- cost alternatives, and those were the alternatives they've signed off on.

And those states would argue strongly, I'm sure, in response to Dick's question, that those are the low-cost alternatives, they've already picked them and it would be, if anything, anti-consumer to upset those decisions.

MR. LARCAMP: Those are sales for resale in interstate commerce. The last time I looked, that was subject to our exclusive jurisdiction to the extent a load serving entity was in turn reselling. I agree it's not the subject of the generation of market power, but affiliated use has always been a part of our customer market based rates.

Some place else in the Commission's continue of looking at it's market based rate program, I do have to tell you that affiliate of use reciprocal dealing transmission of market power, those have all been part of our test from early in the program.

MR. FRAME: I'm not saying otherwise. My point is, I think these are fundamentally resource planning decisions at the local level. Beyond that, it's not apparent to me what nexus there might be at all between the finding of a screen that market power and wholesale markets is a concern, and the mitigation that I'm hearing from Dr. Roach earlier and Steve now, about implementing these bid processes at the state level, I guess I'm imaging hypothetically that there might be a 50 megawatt or 100 megawatt load that potentially might be surfaced as a result of the screening process to be subject potentially to the exercise of market power and this could be in the control area of a large supplier and as mitigation for that.

The answer would be that we would say that the next 1,000 megawatts would have to come from a merchant generator selected in a competitive solicitation process that perhaps is different from the competitive solicitation process that the state is already using. I just can't make that connection.

One final point would be the reference to shared employees. I'm having trouble making that out as something that's bad and not good. If this allows the system to provide power at lower cost than it would otherwise, that sound like a good thing, not a bad thing.

Things like economies of scale and scope are well respected in economics as ways to bring benefits to customers. I would be just mightily opposed to anything that would sacrifice those types of benefits for the customers.

MR. O'NEILL: In the same vein, that's essentially losing the competition of the market. When you are making arguments of scale and scope, you are basically making the argument that the market isn't competitive.

MR. FRAME: I don't think you are.

MR. O'NEILL: The most efficient supplier is a monopolist. You're not making an argument that the market's not competitive?

MR. FRAME: I wasn't making an argument that there is only one supplier in the market, it may be that in some contexts, economies of scope combining two different things produces lower cost. That doesn't mean there is not room for other people to compete as well but I certainly wouldn't want to sacrifice the benefits from this one particular organization, or multiple organizations that they have achieved and been able to lower their costs.

Just because somebody else who has higher costs can't succeed. If you are penalizing the low cost firm to reward the high cost firm, that is not a pro-competitive outcome, that is anything but a pro-competitive outcome. That's anti-consumer.

MR. O'NEILL: What about Steve's argument that you make money on rate based generation but you don't make any money on contractual sales? Is that a bias?

MR. FRAME: I don't know why you can't make money on rate based generation and make money on contractual sales.

MR. O'NEIL: Because it's just traditionally not done. That's the answer.

MR. FRAME: What do you mean it's not done?

MR. O'NEILL: You don't get any profit return on contractual sales. Contractual purchases, the way a vertically integrated utility makes money is on its rate base and the contractual obligations from IPPs are not in the rate base, and don't get a return.

MR. LARCAMP: That's something in terms of purchase power adjustments that the Commission needs to look at to provide a return component to provide an incentive for people to buy, as opposed to using their own rate base.

MR. O'NEILL: As Dave was pointing out, it is a very perverse result to start buying up the independent power producers at the stress places and then turn around and exercise market power in a resale.

MR. FRAME: There are lots of reasons why somebody might prefer a rate based, somebody, a state regulator might prefer a rate based generation versus a purchased arrangement. That stated, when the utility comes in with its proposal, that's the time to check it out to see what alternatives are available, what's the least cost, what risks are involved with this, what risks are involved in that.

MR. O'NEILL: Do you know of any state commission that allows profit markups on wholesale transactions?

MR. FRAME: I can't answer that.

MR. O'NEILL: Do you know of any? That's a yes or no.

MR. FRAME: I don't know of any.

MR. O'NEILL: There you go.

MR. FRAME: No, no, no, you're making a stronger statement like I've looked into it.

MR. O'NEILL: How long have you been in the business?

MR. LARCAMP: I think the point here is that the Commission is not attempting to second-guess state commission determinations with respect to retail purchase decisions.

The Commission has exclusive jurisdiction over sales for resale in interstate commerce by public utilities so that the Commission has an independent assessment to in effect try to deliver on what you just testified, that we want the customer to get the cheapest price reliable power out there. So that we need in terms of our market based analysis to make sure that people are not being excluded from participation in that process. If that happens, we have a market, a wholesale market that is not competitive and one that the Commission then needs to develop appropriate remedies, irrespective of what a state commission does in judging the prudence of a load serving entity's purchase.

They are two sides of the coin, but they are different sides of the coin and the jurisdiction is different. For the Commission, vis- -vis the state commissions.

MR. FRAME: I'm not questioning that.

MR. LARCAMP: That's exactly what's happened for years in cost based rate making as well.

MR. RODGERS: Do we have any questions from those in our audience this afternoon?

MR. LOCKE: Ramier Locke, I'm an independent consultant and a FERC alum, it's a pleasure to be here. I have a question about the market monitoring function. It was originally set up in a one-liner in the Commission's California rulings in 1996. I think the original notion was to have a sort of front line, a self-regulatory function that was set up within the California ISO and the power exchange. Having witnessed the early years of how that worked in those two institutions and how ineffective it was, I was very interested by the impassioned plea, I think it was from the New York ISO representative yesterday that the Commission should keep out of getting in any way involved in monitoring on those markets where you already have that self monitoring-function built in into the ISOs.

My question is really, and it's probably a question that's much directed to the Commission and maybe not answered today as it is to the panelists but my question is, is that function, is the notion of the Commission not getting involved at all in that function still viable? The Commission has now set up its own Office of Market Oversight and Investigation.

Do you see that conflict that I think the representative from New York suggested as being a real one and what is the role of the Commission going to be?

MR. LARCAMP: Before the Commission answers, let me just clarify. I don't think the Commission's staff has ever intended the RTO, ISO market monitors be self-regulating functions except in very clearly defined circumstances where the Commission has authorized them to take action.

One of the problems we saw on California I think is where the market rules were not clear and the Commission has been trying to get those market rules clear since '96. I don't think we intend, nor do I think we can delegate our regulatory responsibility I think vis- -vis, the New York

ISO.

I see them as different products. I don't see anything that the Commission is attempting to do here with respect to mitigation that would trump already approved mitigation and market steps are subject to monitoring and oversight and are being operated by the RTO, ISOs.

MR. RODGERS: Yes, please identify yourself.

MR. CONAHAN: Stephanie Conahan with Wayne Morris. We're counsel to NSTAR Electric and Gas Corporation. I don't have any questions per se but if I may, I'd like to offer up some comments on NSTAR's behalf with respect to some of the issues that have been discussed in the last couple of days.

In the first instance, NSTAR appreciates the Commission's recognition that the hub and spoke method for assessing market power is not well suited to the dynamics of the competitive electric market.

NSTAR also appreciates that the Commission, including staff, is devoting time and attention in an attempt to refine the SMA test which more accurately measures market power in the case of transmission constraints and supply shortages.

NSTAR has two points they would like to make. First, NSTAR wants to echo the views of some of the panelists that were heard yesterday concerning the

Commission's inquiry as to whether the supplier selling into Commission-approved RTOs or IFOs should do market power analyses as part of their base rate application.

The answer to that question is yes. Recognition of market power is the first step towards its mitigation. In some markets, a simple HHI will reveal a substantial market concentration and there is no harm in making that assessment in those cases where market competition has been revealed, the ISO or RTO.

In some markets, a simple HHI may reveal substantial market concentrations that may require the specific vigilance of the RTO or ISO. There is no harm to that assessment if the ISO or RTO has in place effective mitigation measures the seller won't be prejudiced in any way by acknowledging up front that it may have market power upon the occurrence of certain events.

The ISO or the RTO in turn will have a yardstick by which to measure the effectiveness of its mitigation measures and will be less likely to apply mitigation to circumstances suggesting scarcity rents as opposed to the exploitation of market power.

Second, NSTAR submits that capacity should be included in a market power assessment to avoid a situation where a supplier may have market power with respect to capacity even though it's being mitigated with respect to energy.

By way of example, in NEMA, the Northeastern Massachusetts area, a congested area where NSTAR operates, one supplier holds 70% of the available capacity and the two largest suppliers control over 85% of that capacity.

If load serving entities are going to be required to acquire capacity rights on a locational basis, the Commission must assure that suppliers can exercise market power in that arena.

This issue is going to become particularly prevalent in New England where the capacity markets that are being looked at include a requirement to have capacity obligations on a locational basis.

So to conclude, NSTAR would encourage the development of market power screening and mitigation that will take capacity into account. Thank you.

MR. O'NEILL: Can I ask you a question. These issues are very well known because the New England ISO has pointed them out to us. But in the supply market assessment screen as is currently constituted, we would not recognize a load pocket called NEMA. We would recognize all of New England as one control area and we would probably miss this concentration that you were talking about.

So what good is it to supply an HHI in the SMA test where the control area is New England and maybe even larger in some cases, maybe including Hydro Quebec, opposed to the fact that these are all very well known details that both a market monitor and the internal New England ISO personnel are well aware of and have made us aware of.

MS. CONAHAN: It could be that the control area is not the appropriate area to consider for load pockets such as NEMA.

MR. O'NEILL: But we already know through the New England ISO that this is a problem. Why should they have to go to the extra? We would have to devise a whole new set of rules to tell them to file load pocket information. That may be good, but that's not our current test. I assume that they would file under current SMA rules and we would say, uh, no big problem here, because they would file for all of New England.

MS. CONAHAN: There has to be some remedy to address this situation, a situation that as you say is known.

MR. PERLMAN: Can I ask another follow up question? In ISO New England, all the units are effectively treated as individual bidders. They have to bid if they're ICAP units as I understand it, and if they fail some sort of screen or mitigation threshold, they're mitigated for price.

Since they are all individual units that bid and have reference prices and the like that are subject to mitigation on an individual basis, what would concentration analysis tell you about market power at all?

MS. CONAHAN: When you're looking at an area like NEMA, where you have a small number of suppliers who are exerting market power, I guess I don't really understand your question.

MR. PERLMAN: You said if you did in HHI, you would see the concentration in the relevant market, which I would think would be ISO New England since the entities are not treated as a complete firm, they're treated as individual units that bid their own price and are mitigated accordingly.

They de-concentrate it for the purpose of the way the market works and the way mitigation works. You suggest that we look at HHIs. I don't know what that tells you.

MS. CONAHAN: In the context for example of the tri-annual market power analyses, the entity owning these generating units would present an HHI analysis and in NEMA, there is a high concentration of ownership in those generating assets.

MR. PERLMAN: Aren't they subject to mitigation rules today?

MS. CONAHAN: They are subject to the ISO mitigation rules.

MR. PERLMAN: Are those rules flawed in NSTAR's opinion?

MS. CONAHAN: Yes we believe they are flawed.

MR. LARCAMP: Is it true when the states approve the concentration of the generation that the purchasers of that capacity. Do they know that they were seeking market based rates when the purchase price for that capacity was determined?

MS. CONAHAN: I can't answer that question.

MR. RODGERS: Why don't we wrap up now. I have a couple of housekeeping matters I want to mention before we close.

First of all, I want to remind you of what Chairman Woods said at the outset this afternoon, that the Commission has provided an opportunity to file supplemental comments and I understand that they will be allowed to come in until February 4th and so in those comments, I will personally state, I think it will be most helpful to the Commission's staff if the comments indicate not just concerns or criticisms about what staff's proposals were or what someone else's proposals were that were set forth in the panels this week but further, more practical pragmatic solutions on how the infirmities that are perceived exist can be addressed.

MR. LARCAMP: Can we ask that they put that right up front in their executive summary?

MR. RODGERS: I think that would be very helpful. Thank you Dan.

Lastly, the transcripts for this conference, as I understand it, will be available next Thursday. If for any reason you look for them next Thursday and cannot find them or have comments you would like to file directly with Dan Larcamp, I will provide you with his home number right after the meeting today.

(Laughter.)

MR. RODGERS: I'd like to thank our panelists today. Great job again. We are adjourned.

(Whereupon, at 3:45 p.m., the technical conference was adjourned.)