UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Conference on Competition in Wholesale Power Markets	Docket No. AD07-7-000

Written Statement of David M. Ratcliffe
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February 27, 2007

Introduction

My name is David Ratcliffe, and I am Chairman, President, and CEO of Southern Company. Southern Company is the owner of four operating electric utility companies including Georgia Power, Alabama Power, Mississippi Power, and Gulf Power in Florida. In our Southeastern region, we have more than 41,000 MW of generating capacity serving 4.3 million retail customers, at rates significantly below the national average. Our franchised retail service territories cover 120,000 square miles and we have over 27,000 miles of transmission lines. Our fuel mix is 71 percent coal, 15 percent nuclear, 11 percent oil and gas, and 3 percent hydro. We also own a fifth operating company, Southern Power Company, which is a competitive generation company that owns or controls 5,400 MW of generation capacity in the Southeast, serving wholesale customers primarily under long-term contracts. Through both our franchised operating companies and Southern Power, Southern Company is the largest wholesale power provider in the Southeast.

I first want to make it absolutely clear that Southern Company has and continues to fully support wholesale competition. The objective of wholesale competition should be to lower the costs of reliably providing power to retail and wholesale customers. This is our goal. When we are able to buy power cheaper than we can generate it ourselves, we will buy it, and our retail customers benefit. And similarly, when we make sales to displace the higher cost generation of others, the benefits of those sales result in lower rates to our own customers.

We do, however, firmly believe there is more than one model to establish wholesale competitive markets, and not all models will produce the same results when applied to differing circumstances. As a nation, we are still learning what works and what does not. At least until there is clear evidence that a single model consistently provides the most consumer benefits and that other models are incapable of providing commensurate benefits, we believe the Commission should continue to allow regions to adopt industry structures that are best suited for their particular circumstances and retain the most benefits for their consumers. We also believe this was the intent of Congress in passing the Energy Policy Act of 2005.

<u>The Vertically-Integrated, Traditional Model With Bilateral Wholesale Markets</u>

Southern Company is a vertically-integrated utility, regulated under traditional forms of State regulation with regard to sales and service to end-use customers, and by the Commission for wholesale sales and interstate transmission services. Wholesale markets in the Southeast are based on bilateral agreements among market participants. We believe that the vertically-integrated business model coupled with bilateral wholesale markets supports wholesale competition and ensures that its benefits are realized by retail and wholesale customers. I am not here to suggest that the Commission can or should try to "undo" organized markets, require vertical re-integration or return to cost-based wholesale rate regulation. However, we do believe that this traditional model provides numerous benefits that are not readily apparent in the organized markets. Specifically, the traditional model ensures:

- reasonable and stable prices;
- assurance of an adequate supply from diverse fuel sources;
- ability to plan the system in an integrated fashion, ensuring the lowest overall costs of investment decisions;
- a shorter-term wholesale market to provide optimization opportunities – both purchases and sales
- economies of scope through operating an integrated system; and
- clear lines of accountability.

With respect to retail prices, the rates of Southern Company's retail operating companies are among the lowest in the country. Although rising natural gas costs have affected retail rate levels in both organized and bilateral markets, the fuel diversity of Southern Company's generation fleet has been an important factor in mitigating the adverse effects of natural gas price levels and volatility. In organized markets, in contrast, the price of all energy tends to rise to the marginal cost of gas or oil-fired generation in many hours of the year (for example, oil or gas were at the margin 37 percent and coal was at the margin 62 percent of the annual hours in PJM in 2006).[1] This means that even if nuclear power is producing a substantial proportion of the energy required in any of these hours, wholesale prices are still based on the costs of oil, gas, or

[1] Market Monitoring Unit, PJM Interconnection; 2005 State of the Market Report, March 8, 2006, p. 86.

coal. There is no doubt that this market structure results, at least in the short-term, in higher and more volatile prices for consumers than would be the case in a traditional regulated environment. The problem is exacerbated by the fact that practically all generation that has been constructed in organized markets in the past decade has been natural-gas fired, and there is no indication that any significant additional base-load coal or nuclear plants are going to be built in the near future. As organized markets become reliant on natural gas at the margin in even more hours of the year, energy produced by the remaining coal and nuclear plants in those regions will become more expensive to consumers, even as they become fully depreciated. And every time the price of natural gas changes in those markets, so too will the price of energy produced by coal and nuclear facilities, even though the costs of energy produced by coal and nuclear may not be changing in the same manner or to the same degree.

This trend has worked out especially well for the owners of nuclear plants in organized markets (many of which have been fully paid for through stranded cost recovery). However, it is not so clear what the advantage is to the end-use consumer, the presumed beneficiary of competitive organized markets. A good case in point is PJM where there is approximately 30,000 MW of nuclear capacity, constituting approximately 19 percent of PJM's total capability.[2] Nuclear capacity accounted for 243,000 Mwh of generation in 2005, or 34.2 percent of total energy generated.[3] The average operating cost of U.S. nuclear units in 2005 was 17.20 dollars per Mwh[4] compared to PJM's load

[2] Market Monitoring Unit, PJM Interconnection; 2005 State of the Market Report, March 8, 2006, p.134.
[3] Ibid., p.136.
[4] Nuclear Energy Institute; U.S. Nuclear Industry Production Costs, 2005, at http://www.nei.org/documents/U.S._Nuclear_Industry_Production_Costs.pdf.

weighted LMP for 2005 of 63.46 dollars per Mwh.[5] Thus, on average, the PJM nuclear units made over 4.6 cents for each kwh sold, or almost three times their operating costs. The benefits to the nuclear plant owners are clear – but what is not so clear is whether there have been savings to customers sufficient to offset these increased costs.

Southern Company's more traditional model, on the other hand, has been very successful in keeping rates low and stable. Our retail rates are based on our actual costs and not on the vagaries of the hourly spot market. Contributing to the overall success of the vertically-integrated, bilateral model is the fact that wholesale competition in the region is largely predicated on long-term bilateral contracts – an option that has generally not been available in organized markets. One of the primary benefits of long-term contracts is that they provide a financially stable market, including financially stable competitors, from which short-term liquidity (in the form of asset optimization) is achieved. Long-term contracts in our case are a product of both formal competitive bidding processes and bilateral negotiation where load serving entities select for themselves (with appropriate regulatory oversight) the best generation resources (and mix of fuels) to meet their requirements. For Southern Company, these resource solicitation and selection processes are subject to State regulatory review, and resulting wholesale sales contracts are also subject to FERC review.

The traditional model has also served Southern Company and other utilities in the Southeast quite well in terms of supply adequacy. Southern Company has invested $5.9 billion dollars in generation (including environmental control costs and plant upgrades) over the past five years and will invest an additional $8.6 billion over the next three years. Georgia Power Company has just filed an Integrated Resource Plan with the

[5] Market Monitoring Unit, PJM Interconnection; op. cit., p.104.

Georgia PSC that proposes the possible construction of our first nuclear units since the early 1990s – a multi-billion dollar proposition. In addition, the Southeast region has a significant amount of non-utility, competitive generating assets. In fact, more utility generation (37,500 MW) and competitive generation (23,500 MW) has been built in the Southeast region (*i.e.*, the Southeast Electric Reliability Council or "SERC") since 1998 than in any other reliability council, including those covering organized markets. The Southern sub-region of SERC alone has 14,300 MW of non-affiliated, competitive generation. And according to FERC's own statistics, SERC is the only reliability region in the country to have increased its reserve margin over the past three years. (See Figure 1 attached). Moreover, SERC is also the only reliability region projected by NERC to have over a 15 percent reserve margin in 2011.[6] These facts demonstrate that the vertically-integrated model is working quite well to ensure there is sufficient generation to meet customer needs. However, these same projections ought to raise major concerns with respect to generation adequacy in other regions, including the organized markets. Is sufficient generation getting built in those areas to meet future reliability requirements, and if not, why?

The Southeast region in general and the Southern Company in particular have also continued to make significant new transmission investments. Over the past ten years, Southern Company invested $3.4 billion in transmission infrastructure. During the period 2001 to 2005, SERC's net addition of transmission circuit miles (230 kV and above) was greater than the net additions of the Northeast Power Coordinating Council, ReliabilityFirst Corporation, and the Midwest Reliability Organization (the reliability councils covering the New York, New England, PJM and Midwest ISOs) combined.

[6] North American Electric Reliability Corporation; 2006 Long-Term Reliability Assessment, (Oct.2006).

Southern Company will spend an additional $1.8 billion on new transmission facilities in the next five years. And SERC has 1,848 GW-miles of transmission currently being planned, which is more than any of the organized markets, and more than any other reliability council except the Western Electricity Coordinating Council, which covers a significantly larger area.[7]

Mr. William Reinke, the former President and CEO of SERC, recently provided evidence of the significant transmission investment being made by the transmission providers in the Southeast:

> On the transmission side, member [transmission facilities] at 161 kV and above [cover] about 42,000 circuit miles. Planned additions through 2009 include an additional 1250 miles. The interesting statistic here is that the expenditures for transmission in the region that would be all voltage levels for transmission, there is no distribution, will exceed $1.1 billion per year for the next five or six years and it has been over $1 billion the last couple of years.
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> So our member systems are committed to, and are installing more than 25% of the transmission that's being installed in the United States for the foreseeable future. Less than 5% of these transmission expenditures are for generation interconnection. . . .[8]

Clearly, vertical integration is not an impediment to investment that is needed to develop sources of new generation and transmission expansion. To the contrary, these facts and figures prove that the vertical integration model with bilateral wholesale markets supports robust investment in both generation and transmission.

The continued use of integrated resource planning has also contributed to our success. One of the problems that we have observed in organized markets is that

[7] Energy Security Analysis , Inc.; Meeting U.S. Transmission Needs, prepared for the Edison Electric Institute, (July 2005).

[8] Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources, Technical Conference Transcript, p. 140, Docket No. AD05-3, p. 142 (May 13, 2005) ("Regional Planning Conference").

generation and transmission planning is not well coordinated. Accordingly, the resulting generation location decisions or transmission investment decisions often are not optimal from either an efficiency or total cost perspective. In the vertically-integrated model, the franchised operating companies of Southern Company are able to consider and evaluate generation, transmission, distribution, and demand side decisions together when we decide whether to buy or build, and where we will locate generation (if we decide to build ourselves) to minimize overall costs for our customers.

Integrated resource planning has also contributed to the success of our demand-side management programs. For example, Georgia Power has the largest real-time pricing ("RTP") program in the country, with 2,100 customer accounts participating. Georgia Power estimates that with current price patterns, the RTP program saves over 350 MW of capacity due to customer response. The Commission Staff's own 2006 Assessment of Demand Response and Advanced Metering recognized Georgia Power as having the most successful voluntary RTP program in the country.[9] Gulf Power is one of the few utilities in the country with a successful demand-side management program for residential customers, and Georgia Power, at the urging of Georgia PSC Commissioner Stan Wise, is developing a pilot residential RTP program. Southern Company's estimated total capacity savings resulting from both demand response and efficiency programs is about 2,800 MWs. Our spending on these programs is about $90 million per year. Across our four franchised operating companies, we have over 50 demand side and efficiency programs, and we have an additional 25 programs awaiting requisite regulatory approvals.

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[9] Federal Energy Regulatory Commission; Assessment of Demand Response & Advanced Metering, Staff Report, August 2006, Docket No. AD-06-2-000.

By virtue of our traditional business model, Southern Company and other vertically-integrated utilities are also able to take advantage of economies of scope – that is, to operate generation, transmission and distribution in a coordinated manner to provide least-cost solutions. A recent study authored for the Cato Institute points to such economies of scope as one of the critical factors overlooked when many States and regions required divestiture of either generation or transmission.[10] According to the Cato study, consumers in those "unbundled" regions may be facing higher costs as a result of this critical oversight. The ability to operate as an integrated system also ensures that there are clear lines of accountability for ensuring reliability, both in the short-term and the long-term. We have an obligation to provide reliable service to all customers in our franchised service areas, and we take that obligation seriously. The result of our constant attention to reliability and supply adequacy is one of the most reliable electric systems in the country.

Finally, and perhaps most importantly, our customers are satisfied with the results of the vertically integrated/bilateral wholesale market business model. Southern Company has received the highest ranking in customer satisfaction among U.S. electric providers for seven consecutive years by the American Customer Satisfaction Index (ACSI). In the most recent J.D. Power survey of residential customer satisfaction, Southern Company was tied for third in the Nation in overall satisfaction. Interestingly, of the top 15 companies in that survey, 13 of them are vertically-integrated and 11 of those vertically-integrated companies operate in States with traditional cost-of-service regulation.

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[10] Robert J. Michaels, Vertical Integration and the Restructuring of the U.S. Electricity Industry, CATO Institute Policy Analysis No. 572 (July 13, 2006) (available at http://www.cato.org/pub_display.php?pub_id=6462.)

The Status of Wholesale Competition in the Southeast

In addition to our success in serving retail customers, we participate actively in bilateral wholesale markets in the Southeast. We understand that there have been complaints from independent power producers that vertically-integrated utilities do not provide opportunities for competition, but, at least in Southern Company's case, the evidence is clear that the competitive wholesale markets are robust and active. In 2006, for example, Southern Company purchased over 4 million Mwh of power from third parties worth $230 million to replace higher cost energy that we would have otherwise had to generate ourselves. Our estimated cost savings (realized by retail customers in the form of reduced costs of power supply) from these purchases was $23.5 million. It is also important to note that in 2006 we purchased over 1.1 million Mwh from Independent Power Producers for about $102 million, amounting to 28% of our total purchases. Southern Company also made about 5.7 million Mwh of short-term sales. There were 70 different counterparties associated with these sales and purchases.

With respect to longer-term purchases to meet native load requirements over the period 1998 through 2006, the retail operating companies of Southern Company conducted nine long-term capacity solicitations in which respondents submitted over 200 proposals offering over 160,000 MW of power. Contracts for 7,500 MW of capacity were entered into, and Georgia Power is currently negotiating contracts for an additional 2,100 MW of needed capacity. Almost 30 percent of Georgia Power's generating capacity is supplied from wholesale contracts. The ability of our operating companies to enter into long-term contracts for power supply has been a major contributor to our ability to assure supply adequacy, reliability and stable costs.

We believe that organized markets are overly focused on the short-term, and the reluctance or inability of load-serving entities to enter into long-term contracts is a major reason for the lack of generation investment in those areas. We believe that either long-term contracts or rate-based generation will be needed to ensure that additional base-load plants are constructed in both RTO and non-RTO markets. The difference is that non-RTO markets already have those mechanisms in place to encourage the development of such plants. Organized markets are starting to implement capacity markets, which are of course intended to ensure sufficient capacity. But the jury is still out whether capacity markets or administratively determined capacity payments will be able to consistently provide sufficient incentive to sustain the construction of needed new generation in organized markets.

The Need for Regional Diversity

In addition to our belief that competition is working well in our current bilateral wholesale markets in the Southeast, we think it is important that the Commission resist imposing unproven models on regions where there are no clear and sustainable benefits. In the context of the OATT Reform rulemaking, there were at least three proposals for FERC to mandate an industry structure in areas not currently covered by organized markets. These proposals include a paper by Bill Hogan and John Chandley,[11] a proposal

[11] John D. Chandley and William W. Hogan, A Path to Preventing Undue Discrimination and Preference in Transmission Services, FERC Dockets Nos. RM05-25, RM05-17 (filed August 2, 2006).

for “open dispatch” by PJM,[12] and a proposal for transparent dispatch by a group calling itself “Transparent Dispatch Advocates (TDA)”.[13]

These proposals have common themes: (i) the accusation that there is still undue discrimination in wholesale markets that results from vertical integration and a preference for native load customers; and (ii) the claim that the only solutions are to require such utilities to open their dispatch to third parties on a regional basis, and to redispatch their systems on request to provide transmission service when there is insufficient transmission capacity. However, there are some differences as well. At its core, PJM is essentially advocating to impose their full LMP model nationwide. Hogan/Chandley and TDA argue that something short of full LMP markets would be possible. TDA also emphasizes the need for utilities to publish their real-time costs so that redispatch costs can be estimated in advance.

We first take issue with the proposition behind all of these proposals that the current methods for providing transmission service and dispatch in vertically-integrated utilities are inherently unduly discriminatory or preferential. Despite unfounded speculation to the contrary, our commitment and dispatch processes specifically consider purchases from third parties and routinely make wholesale purchases from them when they offer products that; our customers need; are at a price that reduces our costs. And of course, the purchase opportunity must not harm reliability. The current procedures we use, as well as oversight by our State commissions, ensure that our native load customers

[12] Comments of PJM Interconnection, LLC, FERC Docket Nos. RM05-25, RM05-17 (filed August 7, 2006).
[13] Reply Comments of PJM Interconnection, LLC, et al, FERC Docket Nos. RM05-25, RM05-17 (filed September 20, 2006).

get the best deal reasonably possible. Further, we believe there are fundamental differences between point-to-point transmission service and network integration service, and thus principles of comparability do not require them to be the same in all respects. The Commission also has recognized that the customers taking these two types of service are not similarly situated, and do not pay the same for use of the transmission system.[14] And, most importantly, we believe the Energy Policy Act of 2005 made it perfectly clear that the use of the transmission system to serve native load customers first is not unduly discriminatory or preferential.[15] Thus, the claims of discrimination made by supporters of "open" and "transparent" dispatch are based upon a faulty premise.

Southern Company is strongly opposed to all proposals that would mandate such structural change in our region. Importantly, the Energy Policy Act of 2005 set up two processes to study the subject of regional economic dispatch – the first required a study by DOE, and the second established joint boards between FERC and the States to study the issues on a regional basis. Both of these processes have been completed, and their conclusions suggest that, at least in the Southeast, economic dispatch is working well and that there is no basis to require radical changes. In spite of these conclusions, the proponents of organized markets continue to try to impose their own vision of a market model on the Southeast. It seems quite obvious to us that their time would be better spent focusing on how to resolve their own problems rather than trying to spread those problems nationwide. Organized markets such as PJM and MISO are spending close to $250 million a year to operate their systems. Such annual operating costs associated with organized markets would far exceed estimates of potential cost savings that might result

[14] See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, at p. 31,306 ("[A] point-to-point transmission service customer is not similarly situated to native load and Network Customers.").
[15] 16 U.S.C. § 824q(k).

from moving to LMP markets in the Southeast, as was borne out by a SEARUC study conducted by CRA International several years ago.[16]

The Commission stated in issuing its OATT Reform NOPR that it was not intended as an attempt to impose structural changes on any region, and specifically discouraged such suggestions. Nevertheless, the dispatch proposals cited above would do just that. The TDA proposal is the most recent of these attempts, and has garnered some attention because on its surface, it seems as appealing as "motherhood and apple pie" by stating that it merely seeks increased transparency in our business. Indeed, the Commission asked for Supplemental Comments on the TDA proposal. There are significant problems related to offering such redispatch for long-term transmission service. First, contrary to the proposal in the NOPR, long-term firm transmission via "planned" redispatch is not a service we provide to our own native load, and thus it is not necessary to satisfy comparability requirements. If we want to integrate a new resource to serve our retail load, we will ensure that there is sufficient transmission capability to provide service without redispatch. If such capability does not exist, we will build it. We do redispatch resources in real-time, but that is only to maintain reliability given the mix of resources and loads that are currently on the system. Adding a "planned" redispatch would make it more difficult to maintain reliability, as system operators would have fewer resource options to use to address contingencies on the system.[17] Such a redispatch requirement would also serve as a disincentive to the construction of new transmission which is sorely needed in some parts of the country to accommodate wholesale markets.

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[16] "The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast," prepared for the Southeastern Association of Regulatory Utility Commissioners, at 3 (2002).
[17] See Initial Comments of Southern Company Services, Inc., to the OATT Reform NOPR, at 63-80 (discussing the problems associated with requiring redispatch for long-term transmission service)).

One additional particularly troubling aspect of the TDA proposal is its call for utilities to post their actual generation costs in real time. This proposal is anti-competitive. It would give third party competitors information that they could use to alter their bidding strategies and hurt customers. For example, if a third party knew exactly what Southern Company's cost was in a specific hour, it could bid just below that cost and win the bid, whereas without that knowledge, they may have offered an even lower bid. The Department of Justice, in a recent filing related to the Commission's inquiry into Transparency in Markets, made the same point that requiring one-sided information disclosure in the name of "transparency" in electric markets could result in higher prices to consumers.[18]

Participants in TDA include interests who support renewable energy. We recognize the legitimate needs of renewable energy sources, which are often located in remote areas, to get transmission service at reasonable costs. However, supply from such remote sources should not be subsidized by making others pay the high costs of new transmission or transmission upgrades caused by requests for service by remote generators. Likewise, neither should reliability be compromised in the effort to promote renewable resources through the adoption of flawed redispatch or conditional service products. There are other, perhaps better solutions to ensure transmission service to intermittent renewable energy sources. For example, we argued in our comments on the TDA proposal that a properly structured conditional firm service, used as a bridge until there is an opportunity to economically expand the transmission system, would create the ability for renewable sources to get financing without requiring substantial cross

[18] Comments of the U.S. Department of Justice, Docket No. AD06-11 (filed January 25, 2007).

subsidies from utility consumers.[19] But we think a redispatch requirement is contrary to their own interests, as the costs of redispatch cannot be accurately determined in advance, and certainly not predictable for the time frame which would be evaluated to obtain financing for a project. Thus, we think there are better solutions.

If there is a superior solution to providing reliable service to customers at the lowest possible cost, either through organized LMP markets or some kind of hybrid model that attempts to head in that direction, we think that time will tell whether the current organized markets across the country offer real advantages for customers. Until there is a clear sense of the costs and benefits to a region of any particular change in industry structure, and until State commissions support such changes, we do not think that the Commission should impose any model on a utility, State or region.

We are gratified that in Order 890, the final rule on OATT reform, issued on February 15, 2007, the Commission chose not to adopt either the TDA proposal or the other "open dispatch" proposals. There is a "planned" redispatch component of the final rule, but with safeguards attached. We are currently analyzing the final rule to see how "planned" redispatch might be implemented, and will inform the Commission if we see problems.

Nonetheless, we assume that proponents of so-called "open dispatch" markets will continue to argue that a market structure based on vertical integration and bilateral wholesale markets is somehow discriminatory, inefficient, or anti-competitive. We urge the Commission to continue its opposition to imposing major structural changes on regions of the country that are doing well today, such as the Southeast.

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[19] See Supplemental Comments of Southern Company Services, Inc., Docket Nos. RM05-25, RM05-17, at 1-14 (filed December 15, 2006) (discussing the flaws in the TDA proposal).

What Can the Commission do to Improve Bilateral Markets?

While the Commission should not impose any particular industry structure or business model nationwide, we do think there are some actions it might consider to improve the operation of bilateral competitive wholesale markets. For the most part, the Commission is already addressing these issues, and we commend its diligence and foresight in doing so.

First are the issues related to OATT reform. As a general matter, we commend the Commission for proposing a set of reasonable incremental measures to improve the OATT and further ensure that non-discriminatory transmission service is provided. As suggested earlier, we are still evaluating the final rule to see how the Commission's proposals for redispatch and conditional firm service will work in practice and how they will affect our native-load customers, as well as all other aspects of the final rule. We will be sure to inform the Commission of any implementation barriers or concerns.

On the positive side, we are pleased that the final rule adopts one of the most important changes proposed by the NOPR - the Commission's policy on Rollover Rights. The ability to properly plan and expand our system efficiently depends on our ability to forecast expected uses of the system. Past FERC policy that allowed customers to roll over contracts as short as one year with only 60 days notice seriously impaired our ability to effectively plan the system. Order 890's provision that requires a five-year minimum term and a longer notice requirement will improve reliability, promote the provision of service to native load customers, increase market efficiencies by releasing transmission capacity to other customers, and will promote the rational expansion of the transmission grid.

Order 890 also addresses another important issue – regional transmission planning. While Southern Company continues to evaluate Order 890's planning provisions, it bears noting that we have a long tradition of coordinated planning efforts with neighboring transmission owners. This occurs in various ways, including through various reliability coordination agreements and through SERC. In addition to these activities, last year Southern Company introduced two new regional planning initiatives. The first of these initiatives, introduced in November 2006 was the Southern Sub-Region Transmission Planning Summit. Co-hosted by Southern Company, Georgia Transmission Corporation, Dalton Utilities, Municipal Electric Authority of Georgia, Alabama Electric Cooperative, and South Mississippi Electric Power Association, the summit was intended to promote enhanced transparency of the region's transmission planning process and the region's transmission expansion plan, and will be reconvened annually. The second initiative, also introduced at the Summit, was the concept of a Regional Planning Stakeholder's Group.

The Commission also has an on-going rulemaking regarding the standards it will use to evaluate market-based rate applications. We believe that the "indicative screens" proposed to be retained by the Commission are fundamentally flawed and biased against vertically-integrated, load serving utilities. In fact, we believe it is impossible for a load serving, vertically-integrated utility to pass muster under these metrics because they fail to fully address commitment of generation to native load in its "home" control area. The result of the application of the current indicative screens is to require detailed, expensive and seemingly perpetual proceedings in many cases where market power is unlikely to exist. In this regard, it is important to keep in mind that nearly all failures of the Commission's "indicative screens" are failures by integrated utilities in their home control area. Similarly, the Commission's proposal to retain Economic Capacity measures as part of Delivered Price Test-("DPT") analyses also is biased against vertically-integrated utilities with retail service obligations. This is primarily because, while the indicative screens and the Available Economic Capacity measure of the DPT make some allowance for native and requirements loads and for operating reserve obligations, the Economic Capacity analysis makes no such allowance. Again, the Economic Capacity prong of the DPT is a test that is impossible for any vertically integrated utility with service obligations to pass, and is not indicative of any market power that such a utility might have in wholesale markets.

Another problem relates to mitigation measures to address market power concerns. We contend that any mitigation method that requires sales at cost-based rates or includes a "must offer" mandate is inappropriate and harmful to markets. Such measures will distort existing markets because companies found to have market power within their own control areas will be incented to sell outside of their control area (assuming prices outside of that control area are higher than cost-based rates would be in the home control area). Along these same lines, mitigation requirements that focus on a "must offer" rule or that mandate sales at cost-based rates create splits, divisions and seams in wholesale markets that will engender more problems and, at the end of the day will only serve to increase profit margins for power traders and brokers at the expense of customers. If a wholesale seller is found to have market power, mitigation should be narrowly tailored to address the specific reasons why this is the case and then should be based on some kind of price cap based on a regional market price – either from an established index, or based on sales made to and in neighboring control areas.

The Commission recently issued a Notice of Proposed Rulemaking to clarify and update its Standards of Conduct governing transmission providers. Among the issues raised by the NOPR is assuring that integrated resource planning may be conducted effectively and efficiently within the framework of the purposes of the Standards of Conduct. Getting this right will be critical to ensuring that we can continue to meet our State regulatory requirements and expectations with regard to sound integrated resource planning. We will provide specifics of how to accomplish this goal in our planned comments on the NOPR.

Transmission pricing and incentives continue to be important issues that must be adequately addressed in order to ensure both that new infrastructure is built, and that transmission customers face the right price signals. The Final Rule on Transmission Investment Incentives was disappointing in several respects. We think the Commission may have set too high of a barrier for incentive applications, meaning they will have limited value. We were disappointed that the Commission decided to offer additional incentives to transmission-only companies. There is no evidence to suggest that these entities face any additional risks, or that they do a better job than integrated transmission providers in constructing generation. In addition, the Energy Policy Act of 2005, in our view, intended only to provide special incentives to RTO participants, not for those that physically unbundle their transmission assets. We were also disappointed that the Commission declined to clearly end its exclusive use of the DCF method for calculating appropriate returns. This method's unintended result is to drive a utility's market price to its book values. In spite of this, we hope that the Commission will accept alternative ROE methodologies on a case by case basis, and that incentives will prove reasonably feasible in practice.

Another transmission pricing issue that we have raised repeatedly is that of "or" pricing. The current FERC pricing policy, which requires our native load customers to often subsidize transmission and interconnection investment from which they may receive no benefit, continues to be a disincentive to expansion of the transmission system. The Commission's pricing policy should be re-examined to ensure that its pricing policy is consistent with sound economic principles, *i.e.*, that those who receive the benefits of investment should bear the cost burden.

The Commission also has a proceeding underway that was suggested by the Energy Policy Act of 2005 to examine transparency in electric markets. We support transparency where it does not have anti-competitive implications. This means that individual company cost or price information should not be publicly disclosed. We support transparency of transmission information via OASIS, including TTC and ATC calculations. Market transparency can be improved by better defining the products that are bought and sold outside of RTOs. This may be an area where the Commission can provide some assistance.

Finally, Southern strongly supports transaction finality and contract sanctity. Negotiated, bilateral contracts are a foundation of this country's wholesale electricity markets. The recent decision in the Ninth Circuit involving the "public interest standard" has resulted in serious consternation in the industry regarding the extent to which parties to a contract will be able to rely upon their mutually-agreed terms. A deal must be a deal, and should not be subject to perpetual threat of modification whenever a customer decides that it wants to change, or perhaps completely escape, its prior contractual commitments. Southern Company encourages the Commission to take steps to promote contract sanctity so as to encourage parties to enter into the long-term contracts that are fundamental to today's competitive markets. For example, should the Ninth Circuit decision become federal common law, Southern Company recommends that the Commission clarify that its Electronic Quarterly Reporting requirements satisfies the "FERC review and oversight" requirement contained in that order. Furthermore, to the extent a "consideration of all factors relevant to the property of the contract's formation" is part of the Commission's consideration of whether to apply the Mobile-Sierra standard of review, much concern could be alleviated if the Commission states that the focus will be on whether the applicable market was in the midst of major dysfunction or other upheaval (as was the case in the West in 2000 and 2001). By providing such up-front clarifications for how new contracts can satisfy the revised standards, contract sanctity will be promoted.

Conclusions

We wish to commend the Commission for initiating this current set of conferences on competition in wholesale markets. We believe it is time to take a step back and see what is – and what is not -- working in both LMP and traditional competitive wholesale markets. It is clear that there is growing belief that organized markets have some issues they need to address, and there are elements of traditional markets that can be improved as well. We urge the Commission to adhere to basic principles that apply to all competitive markets in mind as it undertakes this examination:

- Competition should be a means to an end, not the end itself. The goal should always be to ensure reliable service to customers at the lowest practicable cost.

- The benefits of wholesale competition can only be achieved through a strong working relationship between the FERC and the States.

- Competitive market rules should not favor one corporate structure, business model, or retail regulatory regime over another. There are many different models that can deliver on the Commission's goal to provide efficient competitive wholesale markets.

- Price signals for generation and transmission in competitive wholesale markets should promote efficiency and avoid subsidies between and among customers and suppliers.

- Ensuring resource adequacy and reliability are absolutely critical in both RTOs and non-RTO areas, and should be the primary focus of the Commission's efforts.

In the Southeast, we believe competitive wholesale markets are working quite well to the benefit of our retail and wholesale customers. While certain incremental Commission actions will help to further improve these markets, we do not see a need for major changes. We have a demonstrated record of building infrastructure to meet the needs of retail and wholesale customers and transmission users in our service area, and with oversight by FERC and our State commissions; we think wholesale markets are working well. There is no evidence that implementing LMP markets or some hybrid of regulated and LMP markets as has been proposed would be beneficial to customers in our region. The current traditional structure of utilities in the Southeast has served consumers well, and we believe it can and will continue to do so well into the future.

Figure 1

Regional Reserve Margins