UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Statement of Duane S. Dahlquist
On Behalf of
Blue Ridge Power Agency

Tuesday, May 8, 2007

Good afternoon Mr. Chairman, members of the Commission, and Commission Staff:

Thank you for the opportunity to appear at today's conference and to relate the experiences of the Blue Ridge Power Agency with competition in long-term wholesale power markets.

My name is Duane Dahlquist and I am General Manager of Blue Ridge Power Agency. Blue Ridge is a joint action agency with 11 members, consisting of eight municipal, one state institution and two cooperatively owned and operated electric distribution systems located across the central, southern and southwestern areas of the Commonwealth of Virginia.[1] Our members provide electric service to more than 350,000 Virginia citizens. Blue Ridge is a small agency, and acts primarily as an aggregator of its

[1] Blue Ridge Power Agency is a non-profit corporation formed in 1988 under the incorporation statutes of the Commonwealth of Virginia. Blue Ridge Power Agency members are: Cities of Bedford, Bristol, Danville, Martinsville, Radford and Salem; the Towns of Front Royal and Richlands; Virginia Tech University; and Central Virginia and Craig-Botetourt Electric Cooperatives

member systems' loads for the procurement of wholesale power supplies. Each member, however, makes its own final power supply decisions and enters into its own power supply contracts. The peak loads of the Blue Ridge members vary from 20 MW to 225 MW.

Our members' electric systems are embedded within the transmission systems of investor-owned utilities, making them transmission-dependent utilities. Prior to the Energy Policy Act of 1992, they were essentially "captive" power supply customers of those transmission owners. All of our members are now within the PJM RTO footprint. Our members often compete at retail with the host investor owned utility, and are very sensitive to maintaining rates as competitive as possible with those applicable in the surrounding investor-owned served communities.

Today, I would like to focus on one of the questions you have posed to our panel:

- Is the perception of inadequate long-term contracting opportunities a matter of different expectations? That is, do buyers, who are not traditional requirements customers of the seller, expect a traditional "slice of the system" at depreciated embedded-cost-based rates, while sellers expect to sell power from generators – new or old – at market-based rates based on the long run marginal cost of new generation?

I am going to focus on the facts on the ground, from Blue Ridge's perspective.

As I see, it, the issue is whether the competitive market is meeting the needs of small to medium size transmission dependent utilities that traditionally relied on regulated wholesale requirements-type purchases from their host investor-owned utilities. Blue Ridge's experience highlights how continued reliance on periodic solicitations for requirements-type, load following power is now far too risky a proposition for municipal utilities with an obligation to provide reliable service at affordable prices to its citizens/customers.

In 1995, after the passage of EPAct 1992, Blue Ridge's members first solicited proposals for alternative power suppliers to see if they could lower their wholesale power costs. At that time, they were in 10-year power supply contracts. Then, we found partial requirements suppliers enabling us to lower our costs for the remainder of our long-term contracts that ended in 1998.

In response to our 1995 solicitation for requirements-type supplies, we had 21 viable bidders. Eighteen of those bid on full requirements contracts and provided us with 85 different proposals at a range of $30.67 per MegaWatt-hour ("MWh") to $40.81 per MWh "as delivered." At that time, transmission costs, including ancillary services, were about $3.50 per MWh. So we were looking at between $27.27 to $ 37.31 per MWh in power bids. In today's dollars, that would be about $35.45 to $48.68 per MWh, assuming 3% inflation.

In 2002 we issued our second solicitation for requirements-type power supplies. This time we had 14 viable bidders providing us with full requirements alternatives ranging from $39.13 per MWh to $57.36 per MWh "as delivered." At that time, transmission charges were running about $4.87 per MWh, including ancillary services. So, we were then looking at between $34.26 to $52.49 per MWh for power only. In today's dollars, that would be about $37.61 to $55.69 per MWh, assuming 3% inflation.

In the meantime, on October 1, 2004, the control areas in which our member systems resided were integrated into the PJM RTO.

In 2005 we issued our third solicitation. This time we received only 8 bids for requirements-type service. The bids ranged from $58.00 to $68.00 per MWh for an "as delivered" product. At that time, transmission charges were running about $3.13 per MWh, including ancillary services. So, we were then looking at between $55.00 to $65.00 per MWh for power only.

In short, in less than 10 years, and under PJM's Day 2 market, we saw prices for requirements-type service from the organized PJM market essentially double. This caused very substantial financial hardships for the Blue Ridge members, many of which were competing for new loads with their neighboring investor-owned utilities charging regulated retail rates based on their state-regulated average costs of service, and certainly a hardship for all of their existing customers.

When the results of the 2005 solicitation were in, our members decided to look at their options in light of a 20-year projection using various supply scenarios. They concluded that they had to do this because continued reliance on periodic solicitations of requirements-type power supply service in PJM's bilateral market was only going to yield ever fewer offers at ever higher prices. They felt that the associated risks were simply too high for not-for-profit distribution entities concerned about meeting their obligation to their customers to provide electric reliable service at an affordable price.

As a result, the Blue Ridge members have taken divergent paths. Some are evaluating signing or have already signed 20-year formula-based requirements type power supply contracts with their traditional investor-owned supplier, on terms less favorable than would have been available to them in the pre-EPAct 1992, pre-PJM Day-2 Market environment).

Others have signed shorter-term (24-30-month) contracts and are working with, or considering working with, a very large joint action agency (with Blue Ridge's assistance) to build a portfolio of asset-based power supply resources that includes generation ownership. For the interim, until those power-supply resources are in service, these members must rely on short-term and long-term **(**1 to 6 year**)** contracts and market purchases through that very large joint-action agency to supply their needs. As TDUs that are too small to build baseload generation themselves, they have been fortunate enough to find a larger partner willing to include them in its efforts. But it will take 6 or more years to complete that portfolio, and in the meantime, they will still have substantial exposure to the vagaries of the PJM markets.

One of our members, Bristol, took yet a different direction. For years, Bristol had been a TVA captive customer and was transmission dependent on TVA. After a long struggle, it obtained congressional authority, in EPAct 1992, to shop for lower-cost power. It did so, and from January 1998 to

December 2004 Bristol contracted for power from a non-TVA supplier at lower rates. As a result of the 2002 solicitation, Bristol ended up with the same rate shock as our other members and signed a 3-year, requirements-type contract. After the 2005 solicitation, Bristol decided to leave PJM entirely and sign a 20-year requirements contract with TVA. In doing so, Bristol is preparing to physically disconnect from PJM, giving up the interconnection it fought so long to get, and reconnecting with TVA.

Significantly, none of our members were willing to risk continued reliance on periodic solicitations of long-term, requirements-type power supply bids in bilateral markets. All of Blue Ridge's members have concluded that such a strategy is simply not viable, given the way bilateral power supply markets in the PJM region are going.

Blue Ridge's members have in some respects been lucky, though I doubt they would see it that way. While they have suffered substantial economic dislocation due to the increased power supply prices they have had to absorb in recent years (in some cases at great pain to their local economies and consumers), they at least have been able to pursue other power supply strategies to reduce their dependence on the PJM market. Since Blue Ridge is a member of the Transmission Access Policy Study Group, however, I know that for many smaller public power systems across the country, other power supply options have not been as available, leaving them at the mercy of the current bilateral market.

What Is Going On?

This Commission, in Order No. 888, acted to provide for "the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition."[2] That promise has yet to be kept.

First, public power systems such as the members of Blue Ridge are seeing fewer and fewer bidders respond to solicitations for long-term requirements-type power supplies. We have seen large utilities that were strong, aggressive contenders in our 2002 solicitation, fall by the wayside in 2005 in response to our request.

Second, we are seeing those that do bid, bid in at substantially higher prices. From what we know of their power supply portfolios, those bids are not based on the seller's own power production costs (including fuel price increases); rather they seem to reflect the clearing prices available in the PJM-run spot markets, which in turn are often set by natural gas fired generation. Bidders appear to be using variations of the same forward natural gas price curves and bidding virtually the same price. The Commission's Staff has, apparently, observed the same phenomenon. In its last State of the Markets Report, FERC Staff reported, "[i]n general, RTO

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[2] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,652 (footnote omitted) (1996).

and bilateral markets both produce prices that largely reflect the cost of fuel for marginal units."[3]

Third, the clearing prices set in PJM's spot markets are affecting the prices and terms sellers in the bilateral market offer for longer term power supplies. The reason is, I believe, simple – why should a generator commit its resources to a long-term contract when it can receive high profits in the spot markets? It is simply more lucrative for many sellers to sell their power into the spot markets.

PJM's Day 2 spot markets allow some generators to receive prices far above their own costs to generate power. This is due to the single-clearing price mechanism used in PJM's spot markets. This point was forcefully made in an August 2006 Report to the Virginia State Corporation Commission. In discussing PJM, that Report stated:

> Since generation units that use natural gas are often at the margin, the bid price (not cost) for these units set the market price for that location. However, it should be noted that while natural gas units are 27.5 percent of PJM's installed capacity at the end of 2005, natural gas generated only 5.9 percent of the total generation in 2005 in PJM. *Over 90 percent of the generation during 2005 was from coal and nuclear units.* This underscores the impact of the marginal-bid price determining market price and its impact on price that retail customers eventually pay.

[3] Federal Energy Regulatory Commission, *2006 State of the Markets Report,* at 19.

2006 Performance Review of Electric Power Markets: Review Conducted for the Virginia State Corporation Commission (August 27, 2006) at 69 (emphasis in original).

Studies commissioned by the American Public Power Association ("APPA") have confirmed the extremely high profits some sellers into PJM's markets are making. One of those studies notes that "[p]rospectively, the subset of PJM Companies [large sellers into the PJM spot markets] who own capacity which was formerly regulated will produce about $4.2 billion per year more in profits than would be earned by typical regulated companies,"[4] When those levels of profit can be made, there is little wonder that there is less interest in offering wholesale customers a reasonably-priced supply that reflects the embedded fleet cost of the supplier.

The promise of open access was that competition would give power suppliers incentives to lower their costs and that those lower costs would flow through to customers in the form of lower prices. Instead what has happened is that sellers with lower cost structures are free to raise their bids to the levels of the higher cost sellers. The competition among suppliers of requirements-type power that existed at the beginning of open access has significantly diminished over time. The pricing available under wholesale requirements-type contracts leaves customers paying prices that make it very difficult for them to compete with the surrounding investor-owned utility's retail rates.

[4] Edward Bodmer, "The Electric Honeypot: The Profitability of Deregulated Electric Generation Companies" (February 5, 2007) at 2.

Blue Ridge's experience is not unique. I have asked other managers of smaller municipal distribution systems in other RTOs, and they have reported similar experiences in soliciting long-term supply. On March 13, 2007, APPA's Legislative and Resolutions Committee passed APPA Resolution No. 07-08. (A copy of that resolution is attached.) That resolution notes the problems that APPA members in RTO regions are experiencing, including: costly and complex LMP pricing regimes; lucrative market prices that provide disincentives to sellers to enter into bilateral contracts that would provide predictability and price stability; inadequacy of Financial Transmission Rights; and escalating RTO costs. That resolution follows an earlier resolution, co-sponsored by Blue Ridge, pointing up the same problems. As a result, APPA has initiated its "Electric Market Reform Initiative" to thoroughly assess what is happening in these markets, and to suggest possible reforms after it has completed that assessment.

What can FERC do?

This Commission has the obligation to ensure that wholesale power supply customers and the consumers they serve pay "just and reasonable" rates for electricity. To do this, the Commission must better understand how prices are set in bilateral markets in RTO regions, and the complicated interactions between RTO spot markets and bilateral markets. The Commission should investigate bilateral contracting practices in RTO regions, assembling a comprehensive picture of who is selling and who is buying, what prices are being offered, what prices are being paid, and what kinds of contract terms are being offered.

The Commission also needs to distinguish between different types of bilateral power supply products in this inquiry. The market for bilateral requirements-type power that follows the loads of smaller utilities may be much different than the market for set blocks of power, with a different universe of suppliers and different terms. Some market participants (for example, independent generators with only a small portfolio of gas-fired units) may not be well-positioned to supply requirements-type power, or even interested in doing so. If this is so, then just "counting the noses" of sellers and buyers in bilateral markets might not be sufficient to identify whether market power exists in certain product sub-markets.

Only after the Commission has a full picture of what is actually going on in bilateral markets in RTO regions will it be possible to develop policies that will foster long-term bilateral contracting, ensure just and reasonable rates in those markets, and thereby provide the long promised benefits of wholesale competition to consumers.

Thank you for the opportunity to speak today and I look forward to your questions.

Resolution 07-08
Sponsor: Minnesota Municipal Utilities Association

In Support of Properly Functioning Wholesale Electricity Markets

Public power systems are facing a critical juncture. Recent developments in Regional Transmission Organizations (RTOs) have created obstacles to public power systems' role as providers of reliable and low-cost electric power to their customers. Because of the problems that have developed in these markets, many public power systems in non-RTO regions have also expressed concerns that RTOs would be expanded to their areas.

Because 70 percent of the energy provided by public power is purchased in wholesale markets, the American Public Power Association (APPA) developed the Electric Market Reform Initiative (EMRI) to perform detailed assessments of the problems in these markets and to develop needed reforms.

APPA has introduced EMRI during this critical time of increasing turmoil to examine what in fact has happened in the power industry, and where we need to go next. EMRI is proceeding in two stages; the first to assess and the second to address market failures and other serious challenges facing public power in wholesale electricity markets across the country.

Public power systems participating in RTOs have encountered a number of problems, including:

- Difficult, complex and costly Locational Marginal Pricing (LMP) schemes that were developed based on the unsubstantiated theory that LMP would create incentives for needed transmission and generation investments;

- Lucrative market prices that provide a disincentive for sellers to enter into long-term bilateral contracts that would provide predictability and price stability;

- Volatile and unpredictable prices that can financially strain public power systems, particularly smaller utilities, if prices spike during a period when a utility has significant exposure to the market;

- Inadequacy of Financial Transmission Rights (FTRs) to hedge transmission congestion costs. As a result, public power systems can no longer plan with any certainty for new long-term generation resources or power-supply contracts;

- Escalating RTO administrative costs; and

- Increasing payments for Reliability Must Run contracts in some RTOs to finance the operation of inefficient generators in transmission-constrained areas.

The first phase of EMRI entails a thorough evaluation of these problems through rigorous analysis and study by various academicians and market analysts with significant expertise in electricity markets. To this end, the first group of EMRI studies was released in early February. These studies show that restructuring of electricity markets has achieved some goals (such as improving operations) but not others, such as lowering prices and providing investment incentives.

In the second phase, APPA will seek to educate policy makers on the problems with electricity markets and needed reforms. Educating members of Congress and Public Utility Commissions on the issues and problems in electricity markets is also central to the initiative, as these entities provide oversight of FERC, RTOs, and electric markets in non-RTO regions.

NOW, THEREFORE, BE IT RESOLVED: That APPA continues to support efforts, like EMRI, to uncover the problems in electricity markets; and

BE IT FURTHER RESOLVED: That APPA urges Congress to hold oversight hearings on the functioning of the wholesale electricity markets and to work with state public utility commissions, the Federal Energy Regulatory Commission and the regional transmission organizations themselves to develop policies that will solve the problems in wholesale electricity markets so that these markets will meet the needs of load-serving entities, benefit electricity consumers, and produce an electric utility industry that can support a robust economy.

Approved by the Legislative and Resolutions Committee of the American Public Power Association on March 13, 2007. The resolutions serve as APPA policy until the entire membership has an opportunity to consider the issues at APPA's National Conference in June 2007.