FERC Standard Market Design Implications

for Public Power Generation

Presentation to

APPA Legal Seminar
Scottsdale, Arizona
October 28, 2002

David P. Yaffe
Van Ness Feldman, P.C.
Washington, D.C.
(202) 298-1840
dpy@vnf.com

For those public power utilities not located in the Northeast or, to a lesser extent, in California, the focus of scrutiny concerning the Federal Energy Regulatory Commission's ("FERC") Notice of Proposed Rulemaking ("NOPR") on Standard Market Design ("SMD")[1] has been on the change in the nature of a load serving entity's transmission rights and the accompanying cost of service. SMD would institutionalize the disaggregation of vertically-integrated utilities by completely separating control and service over the transmission grid from the generation and distribution functions. What has not been focused upon to as great an extent in the discussion are the implications of SMD on those public power and consumer-owned utilities that either by themselves or through the type of ground-up integration exemplified by joint powers agencies and generation and transmission cooperatives will have for the operation and economics of their generation assets.

This paper is not intended to be a comprehensive review of SMD or the subject of market power. It is intended to highlight some of the more important issues concerning the way in which a public power utility's ownership and operation of its generation will change.

I. The "existing" model

For purposes of this discussion, the attributes of SMD will be compared to the "conventional" model of the operation and ownership of generating assets by consumer-owned systems. Large public power systems with substantial service areas and loads constructed relatively extensive generation and transmission facilities interconnected with their load centers in order to meet their obligations to serve. Smaller distribution utilities, whether public power systems or distribution cooperatives, attempted to fix the cost of their power supply by either building generating facilities alone or in conjunction with other systems. Each of these currently owned projects is governed by extensive joint participation agreements that often establish operating committees, appoint managing agents, provide for the allocation of fuel costs and the costs of upgrades. While the cost of generation was largely fixed, or at least identifiable, and could be analyzed separately from the cost of the transmission service required to deliver it. Generation owning utilities were required to obtain sufficient generation to meet area reliability council planning reserve requirements and, perhaps, to have sufficient spinning reserve capacity to meet load in real time. Depending on whether the public power utility was vertically integrated, or served by a joint action agency, it understood that it was obligated to obtain the operating reserves required to deliver energy as firm, but, in many parts of the country, this obligation could be satisfied simply by meeting planning reserve requirements. The only real planning issue then, was how to obtain sufficient generation resources in order to meet the distribution utility's load. The planning equation was driven almost exclusively by the need to meet load projections and not necessarily in order to meet the projected demands of the market as a whole.

In any particular day, the utility would be required to submit a schedule for generation in order to meets its load, and any off systems sales to which it might have

[1] / [citation]

committed itself. The schedule would be submitted to the control area operator in which the generation is located and, if the generation was located in a control area other than the control area governing the utility's load, the control area operators would coordinate the delivery of the output through the interchange calculation. The generation schedule would be submitted on a day-ahead basis, although weekly projections might also have been submitted. The utility owning the generation also might be able to submit changes to the generation schedule up to 20 minutes before each hour in order to better coordinate generation schedules with anticipated load and, thus, minimize imbalance energy. Discrepancies between generation and load in an hour would either be charged out as imbalance energy under the applicable Open Access Transmission Tariff ("OATT") or, as is the case in many parts of the country, would simply be tallied and "made up" on a next-day or next-hour basis through the interchange arrangements between control areas.

II. Changes to the conventional model required by SMD

A. What used to be a relatively linear function, i.e., relating projected load to generation schedules, now becomes a multi-variable type of exercise. First, the public power utility must decide whether to bid its generator, or share of a generator, into the day-ahead and energy and ancillary service markets and, concomitantly, to schedule to purchase its load energy requirements from the day-ahead energy market or whether to submit a balance schedule matching generation to load, and not bidding the generation into either market. Even if one attempts to self-schedule, the issues are not finished.

First, it is not clear whether a self-schedule is entirely free from the requirement to bid the output into the day-ahead energy market. At least in the market administered by the New York Independent System Operator ("NYISO"), a self-schedule is to be made together with an incremental or decremental bid, the indication of the minimum cost of energy in the day-ahead market below which the entity making the schedule would be willing to buy energy from the market instead of from the specifically scheduled generation. Moreover, if the schedule of generation from your generator to your load would require delivery across a congested interface, the utility may be required to determine whether to pay the cost of congestion in order to complete the delivery of the output or to buy energy from the market inside the constraint and not to schedule the generation.

Second, even if the utility operates under the philosophy of scheduling generation primarily to its load, there will be hours, if not days or seasons, in which the load may be substantially less than the capacity of the generator or the ownership percentage. As will be discussed below under market mitigation, the utility may still be required to submit bids to sell either energy or, regulation or operating reserves into the market administered by the applicable RTO/ITP on both a day-ahead and real-time basis. These choices will have different implications, depending on whether the generation is base load or peaking, and whether the utility has sufficient Congestion Revenue Rights ("CRR") in order to cover the cost of congestion between the generator and the load.

In the alternative, the utility may take the philosophy of bidding all of its generation into the day-ahead and real-time energy markets administered by the RTO and purchasing all of its energy requirements from the market. This choice may be made either because of the structure of the market, because of the possibility that generation and load may be located in markets administered by different ITPs and the cost of delivering across a seam may be either prohibitive or prohibitively complex. If the utility undertakes this philosophy, or its generation consists of peaking units that would not be scheduled to meet base load needs in any circumstance, the utility will need to follow and become familiar with the nature of the markets within which it operates, understand the location of constraints and how it may affect the price that can be received for energy delivered from the unit, and determine what its likely pattern of dispatch will be in LNP dominated market.

For peaking units or otherwise for energy limited resources, the owner must understand the limitations on the unit and work to mold the rules for bidding in order to accommodate the limitations of the resource.

Although these issues are sufficiently complex for a utility that controls generation, it becomes even more complex for dealing with jointly owned facilities. Discussions need to be made with the operating agent for the facility about the theory of bidding the output of the generating unit into the day-ahead and real-time markets, how to share revenues for each hour of the day, and how to communicate the result of each day's bidding to the market participants, particularly those that depend on self-scheduling to meet their loads. Issues of bidding strategy also need to be worked through. In particular, the affect of cascading bids for energy, spinning reserve, operating reserve, and regulation also need to be understood. [at beginning of section, discuss the issue of philosophy of operation.]

B. Order 2000, concerning RTOs, as well as the SMD NOPR, require the RTO to administer market power mitigation measures. Market power mitigation is intended to address two types of exercise of market power: physical withholding of generation from the market, and economic withholding of generation from the market; both intended to result in the increase of market price above the level that would be sustained in a competitive market. The SMD NOPR requires that an independent market monitor conduct an inventory of market conditions in each market administered by an RTO. The inventory is to identify all transmission constraints, all load pockets [define load pocket], i.e. areas in which generation is exceeded by load and that the withholding of generation can increase price.

According to the SMD NOPR, the independent market monitor is to enter into a participating generator agreement with those generators which it identifies as being able to exercise market power. It is not clear whether the participating

generator agreement applies to all generators, or only selected generators identified by the independent market monitor.

Among the conditions that may be imposed on a generator through a participating generator agreement are a requirement that the generator is required to run during periods identified by the RTO ("RELIABILITY MUST RUN") and to specify the cost-based revenues to be collected for such operation or, in the alternative, specify the conditions under which the operator of the generation is required to bid all available output into the energy market and the maximum price at which such output can be bid. It is not clear from the SMD NOPR whether such participating generator agreements must be filed with the FERC or the penalties for violation of the PGA. To the extent however, that a generation owned by a public power utility becomes subject to a participating generator agreement with either reliability must run or must offer requirements, the net result is that the generation may be required to run in order to stabilize prices in the market at times and in amounts that are different from those needed to meet the generator's load requirements.

One of the byproducts, however, of the requirement to prevent withholding may be the opportunity for a utility to lay off capacity that it does not need for a season or longer period. The SMD NOPR requires all load serving entities to meet a resource adequacy requirement in the form of identifiable contracts for generating capacity equal to the LSE's load plus a reserve margin established by the RTO in conjunction with the Regional State Advisory Council.