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January 31, 2003

Honorable Magalie R. Salas,
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1-A209
Washington, D.C. 20426

Re: Docket No. RM01-12-000 - Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electric Market Design

Dear Secretary Salas:

For filing, please find the additional Comments of the New York State Public Service Commission in the above-entitled proceedings. Should you have any questions, please feel free to contact me at (518) 473-8178.

Very truly yours,

David G. Drexler
Assistant Counsel

Attachment

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electric Market Design	)) Docket No. RM01-12-000)

ADDITIONAL COMMENTS OF THE NEW YORK STATE PUBLIC SERVICE COMMISSION ON THE STANDARD MARKET DESIGN PROPOSED RULEMAKING

On July 31, 2002, the Federal Energy Regulatory Commission (FERC or Commission) issued a Notice of Proposed Rulemaking (NOPR) for establishing a national Standard Market Design (SMD). The New York State Public Service Commission (NYPSC) embraces the goal of the SMD NOPR to "remedy remaining undue discrimination and establish a standardized transmission service and wholesale electric market design."[1] We applaud FERC's willingness to embark on this complex effort. Pursuant to the SMD NOPR, the October 2, 2002 "Notice of Conferences and Revisions to Public Comment Schedule" and the December 20, 2002 "Notice on Requests for Additional Time," the NYPSC hereby submits its comments on transmission planning, long-term resource adequacy, and state participation in regional state advisory committees (RSACs).

[1] SMD NOPR at ¶3.

OVERVIEW AND EXECUTIVE SUMMARY

On November 15, 2002, the NYPSC filed comments supporting FERC's objective to "create 'seamless' wholesale power markets that allow sellers to transact easily across transmission grid boundaries and that allow customers to receive the benefits of lower-cost and more reliable electric supply."[2] The proposed SMD is a major step toward establishing larger markets and eliminating many of the existing seams problems of the kind we experience in New York that hamper trade between regions. We urge the Commission to accommodate regional variations, provided those variations do not affect the efficiency and reliability of the markets.

The NYPSC agrees that planning on a regional scale makes good sense. The proposed regional planning area for the Northeast should be expanded to encompass not only New York and New England, but also PJM. The relationship between the flow of power among New York, New England, and PJM strongly supports such a larger planning area, as well as the participation of Canada and states bordering Lake Erie. Along those same lines, we reiterate our November 15 proposal that the Commission establish a separate proceeding to eliminate the export and

[2] SMD NOPR at ¶9.

wheel-through charges for the Northeast.[3] In addition, Independent Transmission Providers (ITPs) should not be responsible for mandating transmission expansions or for issuing requests for proposals for transmission. Instead, a market-driven approach is more consistent with a competitive framework. Further, Transmission Owners (TOs) in New York and in other areas should be involved in performing system impact and facilities studies for interconnections and for transmission expansions given their extensive knowledge of and expertise in how local systems are designed and operated.

Regarding resource adequacy, the NYPSC agrees with the Commission that adequate generation and demand response resources are critical components of a competitive and reliable electric system.[4] However, robust forward capacity markets *and* spot capacity markets are both crucial to the development of those resources. Resource adequacy is best ensured by plans that reflect regional variations, such as the proposal contained herein, in cooperation between the Commission and states.

Under the NYPSC's proposal, each LSE would be responsible for the cost of obtaining 50% of its resource needs three years

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[3] NYPSC Comments at 3.

[4] However, we question the Commission's legal authority to require load serving entities (LSEs) to purchase capacity or to penalize them or retail customers if they do not.

in advance either through a direct purchase via contracts or through a centralized auction administered by the ITP. The proposal also contemplates that LSEs would be expected to purchase capacity on the spot market at a price that results from the market response to an administratively established demand curve. The plan would require the NYPSC to set forth its expectations regarding LSEs’ prudent capacity purchases in the forward and spot markets and the Commission to direct the ITP to administer centralized forward and spot auctions.

Finally, we agree with the Commission’s proposal to establish a formal role for states to participate in the decision-making process of ITPs. RSACs could be an important vehicle to address state concerns and convey those concerns to the ITP and FERC, but they should not be viewed as the sole forum for states to raise issues, either individually or collectively, before the ITP or the Commission. For example, the National Governors Association’s proposal to form Multi-State Entities (MSEs) could provide a more effective vehicle than RSACs for examining regional planning and siting of transmission lines.

DISCUSSION

I. The New Transmission Service (SMD § IV.C.)

Transmission Owners Should be Involved in Performing System Impact And Facilities Studies For Interconnection (SMD § IV.C.8.)

The NOPR states that the ITP "will need to conduct system impact and/or facilities studies for service involving the interconnection of a new load or generator."[5] However, the NOPR is silent on the role of TOs in performing such studies. Therefore, we seek clarification that TOs that have no incentive to treat generation affiliates preferentially should be permitted to conduct these studies, which would then be reviewed by the ITP.[6]

The TOs are uniquely qualified to model, study, and evaluate the transmission system. They have significant experience performing system impact and facilities studies. On the other hand, the ITP may not have the necessary detailed understanding and knowledge to perform studies affecting the local transmission and distribution system. Thus, while the ITP should take the lead in coordinating inter-regional and bulk power transmission planning, the TOs should be allowed to

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[5] SMD NOPR at ¶157.

[6] In New York, TOs have divested practically all of their generation facilities. Therefore, the incentive for TOs to treat generation affiliates preferentially is no longer present.

conduct system impact and facilities studies for their portion of the ITP region and the local level. Accordingly, the Commission should clarify the roles of the ITP and TOs in the final rule.

II. <u>The New Congestion Management System</u> (SMD § IV.E.)

The proposal to manage transmission congestion using Locational-Based Marginal Planning (LMP) and Congestion Revenue Rights (CRRs) is reasonable and has proven successful in the NYISO. However, until the market for CRRs has sufficiently matured, CRRs should be auctioned for short terms in order to avoid price distortions and to allow for improvements in market rules.

<u>Congestion Revenue Rights Should Be Auctioned For Short-Terms</u> (SMD § IV.E.3.e.)

The SMD NOPR proposes to require the ITP to conduct periodic auctions of CRRs.[7] The Commission asks whether the ITP should be required to "offer multi-year [CRRs] when [SMD] is first implemented."[8] The NYISO experience with multi-year auctions demonstrates that auction results undervalue the worth of the CRRs. In September 2000, the NYISO conducted auctions

[7] SMD NOPR at ¶252. The SMD pro forma tariff defines CRRs as "[a] property right held by a customer that entitles and/or obligates the holder of the right to receive specified Congestion revenues." SMD NOPR at Appendix B, p. 15.

[8] SMD NOPR at ¶249.

for five-year terms and two-year terms. The five-year transmission rights sold for approximately the same price as two-year transmission rights, which suggests that the rights for years three through five had little or no value.[9] Moreover, while the design of transmission rights and auctions are still evolving, auctions for short-term periods provide greater opportunities to adjust market rules, whereas auctioning off long-term rights may hinder improvements.[10]

III. <u>Standard Market Design</u> (SMD § IV.G.)

In general, we support the Commission's proposal to evaluate transmission planning and expansion on a regional basis. A regional approach is best suited to finding the most efficient and optimal solution at the least cost. We suggest the following changes to the SMD.

[9] Specifically, transmission rights for five years (2000-2005) from the reference bus in western New York to the Indian Point 2 bus sold for an average of $164,308 per TCC/CRR (averaged across four auction rounds), while the same rights for two years (2000-2002) sold for an average of $158,854 per MWh (averaged across three auction rounds). As such, the rights for years three through five effectively sold for just $5,454.

[10] Market participants will likely be resistant to implementation of market enhancements if the economic value of their CRRs is adversely affected over a long period of time.

A. **Transmission Owners Should Be Allowed To Calculate Transmission Capability And Perform Facilities Studies For Transmission Expansions (SMD § IV.G.2.)**

The NOPR states that "calculations of transmission capability and the performance of facilities studies for transmission expansions must be performed by an independent entity to reduce the opportunity for preferential treatment by the transmission provider."[11] The Commission's goal to reduce preferential treatment by TOs is reasonable, but a one-size-fits-all model could produce an inefficient outcome.

It is essential that TOs be able to perform studies for transmission expansions. The TOs are uniquely qualified, given their knowledge and expertise, to model, study, and evaluate the non-bulk transmission system. They have specialized knowledge of local system operations and impacts critical to the planning process. As such, TOs should be allowed to calculate transmission capability and perform facilities studies in coordination with the ITP. The ITP's involvement and oversight of the TOs' studies should ensure that the results are accurate and impartial. Furthermore, concerns over preferential treatment have been reduced in New York, where transmission providers (i.e., TOs) have divested practically all of their

[11] SMD NOPR at ¶333.

generation facilities.[12] Accordingly, the incentive to treat their generation affiliates preferentially has been minimized.

B. A Regional Planning Area Should Include The Entire Northeast (SMD § IV.G.3.)

The SMD notes the importance of coordinating transmission planning and expansion on a regional basis in order to optimize solutions. According to the NOPR, NYISO and ISO-NE would constitute a regional planning area.[13] However, such a limited planning region for the Northeast is inadequate and could lead to the inefficient use of transmission and generation facilities. Instead, the planning region should be expanded to also include PJM. In addition, the planning process should involve the participation of the Lake Erie states (i.e., Michigan and Ohio) and Canada.

The markets and the existing transmission grid in the Northeast and neighboring regions frequently result in significant power flows between and among New York, New England, and PJM. Given such power flows, it is essential that all these regions be integrated into a planning region, as is currently done on an *ad hoc* basis. Moreover, various current planning studies involving the Northeast Power Coordinating Council

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[12] Also, while integrated utilities are not the norm in New York, integrated utilities, absent a particular finding, may not have the incentive to engage in preferential treatment.

[13] SMD NOPR at ¶343.

(NPCC), the Mid-Atlantic Area Council (MAAC), and the East Central Area Reliability Council (ECAR), encompass NYISO, ISO-NE and PJM, in addition to the Lake Erie states and Canada.[14] Therefore, we would expect NPCC, MAAC, ECAR, the Lake Erie states, and Canada will continue to participate in Northeast planning studies regardless of the formal definition of the planning area.

Moreover, we envision a process whereby each ISO/RTO/ITP within the planning area determines its own estimates of load growth and anticipated capacity. The ITPs would develop a common set of assumptions to the extent possible and work together on a final plan. The MSE would then review the plans.[15]

C. The Independent Transmission Provider Should Not Be Responsible For Approving Transmission Expansions Or Issuing Requests For Proposals Under The Planning Process (SMD § IV.G.3)

The NOPR proposes that under the regional planning process, "an Independent Transmission Provider should have the responsibility to issue requests for proposals when the planning process determines that additional resources are needed to serve the regional market. Parties may respond with proposals to

[14] As the SMD properly suggested, the Northeast regional planning process should "encourage participation by Canadian entities and provincial authorities." SMD NOPR at ¶340.

[15] See, infra, pp. 40-41.

expand the grid, add generation (including distributed generation), or implement demand response."[16]

The ITP should not use requests for proposals (RFPs) as the vehicle for ensuring system adequacy, nor may the Commission authorize this technique under the Federal Power Act.[17] Rather than issuing specific RFPs that prejudge solutions and bind the ITP, the ITP should make the results of its needs assessment publicly available and allow the marketplace to respond with transmission, generation, and/or demand response projects. Responses may be in the form of interconnection study requests and/or siting applications in the relevant jurisdictions.

It would be a step back to require the ITP to procure generation and demand response through RFPs because the marketplace is better suited to making the most efficient investment decisions than is the ITP. Similarly, it is unreasonable for the ITP to perform least-cost comparisons of market proposals when the market participants will be assuming

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[16] SMD NOPR at ¶348.

[17] The Federal Power Act does not permit the Commission to order transmission expansions except in the limited instance where a wholesale generator, electric utility or a Federal power marketing agency seeks a Commission order requiring a transmission owner to provide transmission services, including an enlargement of transmission capacity, under specific conditions. 16 USCA § 824(j).

the risks and receiving the benefits associated with a project.[18] Moreover, instead of relying on the ITP to force TOs to build, FERC should leave approval of transmission expansions to the states, which have ultimate authority over siting and can better analyze the associated impacts.

D. Transmission Owners Should Be The Builders Of Last Resort (SMD § IV.G.3)

The proposal to designate TOs as the "transmission builder of last resort"[19] is reasonable because it would ensure that transmission upgrades necessary to maintain reliability are completed. However, the market should be relied upon in the first instance to indicate to market participants the need for other transmission upgrades.

Notwithstanding the foregoing, there should be a recognition that states currently retain the authority to direct TOs to build reliability and/or economic projects whenever they are deemed to be in the public interest. Moreover, the SMD should not preclude the possibility that merchant entities may play a role as builders of last resort in the future.

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[18] Shifting the risks associated with capital investment from customers to suppliers of risk capital is one of the benefits of a competitive wholesale market.

[19] SMD NOPR at ¶350.

IV. <u>Long-Term Resource Adequacy</u> (SMD § IV.J.)

The NYPSC agrees with the Commission that adequate generation and demand response resources are critical components of a competitive and reliable electric system.[20] The SMD NOPR properly observes that (1) the energy spot market is not, as currently constituted, able to induce long-term reliability investment; (2) individual load serving entities (LSEs), especially when faced with retail competition, have the incentive to lower their supply costs by depending on the resource development investments of others (the free rider issue); and, (3) demand response is in its infancy.[21] Because electricity is a public good, administrative intervention to ensure reliability is required.[22] However, in contrast to the NOPR's almost exclusive focus on forward contracting, robust forward capacity markets ***and*** spot capacity markets are both

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[20] An issue pertaining to resource adequacy that has not been addressed in the NOPR but has a significant impact on resource adequacy is the role natural gas plays in meeting electric demand. Inasmuch as most new generation relies on natural gas for its fuel, the NYPSC has begun to study whether the gas infrastructure in New York is adequate to support electric power generation supplying the State. We urge the Commission to initiate a proceeding and hold a technical conference to address the adequacy of the gas infrastructure on a regional and national basis.

[21] SMD NOPR at ¶¶457-473.

[22] <u>See</u>, <u>infra</u>, Appendix A at pp. 4-5.

crucial to the development of those supply and demand response resources.

The SMD's approach to resource adequacy should be revisited. Not only does the Commission lack jurisdiction to require LSEs to purchase capacity, but the proposal would hamper retail competition. Further, it does not address the free rider issue, and it is doubtful it would achieve the objective of providing for sufficient supply and demand resources. We understand that the Commission Staff has come to appreciate the shortcomings of the resource adequacy section of the SMD as a result of the November 19, 2002, technical conference and other discussions with interested parties. Resource adequacy is best ensured by plans that reflect regional variations, such as the New York program, and cooperation between the Commission and states.[23]

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[23] The NYPSC continues to participate in the deliberations of PJM's Resource Adequacy Market (RAM) Group, previously known as the Joint Capacity Adequacy Group (JCAG), which also includes the New York and New England ISOs and their market participants. Many of the aspects of the RAM Group's current thinking on capacity issues are attractive. However, the RAM Group's approach is inadequate in two ways. First, it does not include a centralized spot market. Second, it requires that LSEs purchase 100% of their resource needs several years in advance through a centralized auction process. The NYPSC will continue working with this group as it refines its proposal and may file additional comments if the RAM Group or the three Northeastern ISOs file a complete proposal.

The NYPSC's proposal, discussed below, includes, among other things, the expectation that each LSE would purchase 50% of its resource needs three years in advance through a centralized auction administered by the ITP (or via bilateral contracts). The proposal also contemplates that LSEs purchase capacity on the spot market at a price that results from operation of an administratively established demand curve. The plan would require the NYPSC to set forth its expectations regarding LSEs' prudent capacity purchases in the forward and spot markets and require the Commission to direct the ITP to administer centralized forward and spot auctions. As such, the plan cooperatively applies the separate but complimentary federal and state jurisdictions to the resource adequacy issue in a manner consistent with the recent article entitled, "We Can Work It Out," authored by Commission Chairman Wood and NARUC's former President, William Nugent.[24]

A. The Commission And The States Must Work Together To Implement A Resource Adequacy Regime

1. The Commission Does Not Have Authority To Require LSEs To Purchase Capacity Or To Penalize Them Or Retail Customers If They Do Not

The Commission proposes to require every LSE to demonstrate to the ITP that it will have resources in place for a set number of years in the future (the planning horizon) to satisfy its

[24] *Public Utilities Fortnightly*, January 1, 2003.

forecast peak plus a capacity reserve margin.[25] Under the SMD proposal, two mechanisms are contemplated to enforce this requirement: "(1) a Commission-set tariff penalty imposed on a load-serving entity that threatens reliable transmission operation by taking energy from the spot market during a shortage [ ] in a year for which it fails to meet its resource adequacy requirement; and (2) a Commission requirement that the spot market electric service of such a load-serving entity must be curtailed first when the shortage is severe enough to require that some customers be curtailed."[26] Moreover, the Commission proposes to set a minimum reserve margin of 12%. These aspects of the SMD are flawed because the Commission may not: (1) require LSEs to purchase capacity; (2) penalize them if they do not; (3) curtail service to retail customers of

[25] NOPR at ¶493. The term "reserve margin" as used in the NOPR relates only to capacity and not to other components of the electric system/market necessary to ensure safe and adequate service to customers such as transmission and distribution. In New York, reserve margins result from NYISO and New York Reliability Council calculations that relate to one-day-in-ten-years loss of load expectation (LOLE) analyses.

[26] NOPR at ¶527.

“deficient” LSEs, or (4) set a reserve margin.[27]

The Federal Power Act (FPA)[28] provides that for a transmission or sale of electric energy to be subject to the Commission’s jurisdiction it must be an interstate transmission of electric energy or a wholesale sale of electric energy for resale. Accordingly, the Commission has jurisdiction over wholesale transmission, wholesale commodity, wholesale distribution, and unbundled retail transmission.[29] The states, in contrast, have jurisdiction over retail distribution, retail commodity, and bundled retail transmission.[30]

The Commission’s authority with respect to transmission and sales extends to the rate, charge, classification, rule, regulations, practice, or contract of a public utility that transmits electric energy in interstate commerce and/or sells

[27] As the NOPR acknowledges at ¶481, traditionally reliability councils such as the North American Reliability Council (NERC) and other regional reliability councils, utilities, and states working together have established capacity reserve margins. Yet, in the NOPR, the Commission has taken the novel step of proposing that it “adopt a 12 percent reserve margin as a minimum regional reserve margin for all regions….” SMD NOPR at ¶493. Establishing an arbitrary minimum would send a message that meeting a set reliability standard is optional. Any minimum must satisfy the Northeast Power Coordination Council’s (NPCC’s) one-day-in-ten-years standard to avoid degradation of reliability, and should not be an arbitrary number. ITPs should have the option of adopting stricter standards.

[28] Sections 205 and 206 (16 U.S.C. §§ 824d and 824e).

[29] New York v. FERC, 122 S.Ct. 1012 (2002).

[30] Ibid.

electric energy at wholesale in interstate commerce. Thus, the Commission historically has issued orders requiring a new rate or practice thereafter to be observed by a public utility for any transmission or sale it made that was subject to the Commission's jurisdiction.

Here, in contrast, the Commission is attempting to impose requirements on the *purchaser* of electric energy at wholesale in interstate commerce. The Commission defines the purchaser (or LSE) as "any entity that uses transmission in interstate commerce to provide power to load."[31]

The Commission can no more use its jurisdiction over transmission service to control the behavior of retail sellers of electricity than state regulatory commissions may use jurisdiction over retail distribution to mandate certain behavior by retail consumers. Just as the NYPSC cannot, under the auspices of maintaining a reliable distribution network, penalize Sears for failing to contract for a certain amount of retail electricity, the Commission cannot point to its jurisdiction over the transmission system as justification for penalizing the supplier of Sears (i.e., an LSE) if that retail utility does not contract for a certain level of wholesale

[31] The Commission also defines "a large retail industrial or commercial customer that has retail access rights and buys power directly from suppliers" as an LSE for purposes of the reserve margin requirement. SMD NOPR at ¶495.

purchases.[32] Similarly, the Commission does not have authority to interfere with the consumption of electricity by retail customers by implementing selective curtailments.[33]

The Commission's claim, moreover, that its adoption of a reserve margin is necessary to "operate the interstate transmission system reliably"[34] fails because it confuses adequacy of supply and reliability of the system. These are actually two very different concepts and are not interchangeable as the NOPR's discussion suggests. As a practical matter, there is no nexus between the establishment of a reserve margin and the reliable operation of the transmission system. The reserve margin is a generation adequacy requirement designed to ensure that load is not lost due to an inadequate generation supply. It may have the effect of increasing generation supply which, depending on location and demand, may result in greater

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[32] As the Supreme Court noted in New York v. FERC, 122 S.Ct. at 1026, FERC does not have jurisdiction over retail uses of the local distribution system. The Commission may not use its jurisdiction over wholesale transmission, wholesale commodity, and wholesale distribution and the physical and economic relationships between activities on the bulk power system and activities on the distribution system to assert jurisdiction over retail matters. See, e.g., AT&T Corp. v. Iowa Utilities Bd., 119 S.Ct. 721, 731 (1999), where the Court found that absent specific Congressional authorization the Federal Communications Commission could not take "intrastate action solely because it furthered an interstate goal."

[33] Id.

[34] SMD NOPR at ¶493.

accessibility over the existing transmission capacity, to the enhanced supply of generation, but it does not change the capacity of the transmission system for moving power, nor does it result in greater reliability of the transmission system.[35] Transmission system reliability is a separate issue that addresses the ability of the system to deliver generation to load. Although the Secretary of the Department of Energy is authorized to request reports from the Commission and reliability councils concerning any electric utility reliability issue and recommend industry standards for reliability to the electric utility industry,[36] neither the Secretary nor the Commission is authorized to take the actions sought to be implemented in the NOPR.

2. The Commission And The States Together Should Implement A Resource Adequacy Program

While the architecture of wholesale sales is a matter for Commission regulation,[37] state jurisdiction over retail electric

[35] The NOPR also contends that its adoption of a reserve margin will avoid "poor market liquidity" and "shortages with sustained high wholesale power prices." SMD NOPR at ¶493. Because a reserve margin, by definition, forces purchasers to have access to more generation supply (i.e., capacity) than they actually need to meet demand, this statement may be true, but it is irrelevant to the question whether the Commission has authority to set reserve margins.

[36] 16 U.S.C. §824a-2.

[37] See, Mississippi Power and Light Co. v. Mississippi, 487 U.S. 354 (1988).

rates includes authority to disallow imprudent purchases from wholesale suppliers.[38] Further, state regulatory commissions generally are empowered to order particular utility purchases, capital improvements, or any other actions needed to assure the provision of reliable retail service.[39]

Inasmuch as the states have jurisdiction over reliability and over LSEs' retail service (indeed, a statutory responsibility to ensure the provision of safe and adequate service at just and reasonable rates), it is the states, therefore, not the Commission, that may actually prescribe capacity portfolios.[40] The Commission, on the other hand, has jurisdiction over the ITPs and should use that power to shape and enforce the wholesale elements of the resource adequacy program, such as setting the demand curve's capacity prices and administering a centralized auction, that would be implemented by the ITPs. In part C of this section, the NYPSC proposes such a program.

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[38] See, Pike County Light & Power Co. v. Pennsylvania Public Utility Comm'n, 77 Pa. Commw. 268, 273-74, 465 A. 2d 735, 737-738 (1983).

[39] See, e.g., New York State Public Service Law (PSL) Article 4.

[40] See, e.g., PSL §§ 66(2); 65(2).

B. <u>The SMD's Resource Adequacy Proposal Is Seriously Flawed</u>

1. <u>Complete Reliance On Forward Capacity Markets Absent Spot Capacity Markets Would Impair Retail Access And Jeopardize Reliability</u>

The absence of a spot capacity market[41] to accommodate load shifting and load growth is a significant flaw of the SMD proposal. All markets require spot markets to balance demand and supply. Electric markets similarly require spot markets to accommodate retail access as well as to react to unforeseen events such as higher than expected load growth, delay of new generation, or plant closures. Spot markets can also provide an indication that a reliability problem is developing.

Because capacity obligations under the SMD approach would be set a number of years in advance, the probability is high that the forecasts would prove incorrect. The SMD does not have a provision for requiring more capacity purchases if, subsequent to the forward market activities, an increase in actual load growth above the level that was forecasted causes a potential near-term shortage.

Equally important, the Commission's proposal would create a significant barrier for small LSEs by requiring them to (1) forecast future obligations several years out, and (2) take financially binding forward positions without load. The SMD

[41] Hereafter, the use of the term "spot markets" will always refer to "spot capacity markets" unless otherwise stated.

approach would add significant costs and risks to low-margin retail businesses that they are ill-equipped to absorb and that they may not be able to pass on to customers, because they often compete against TOs' retail rates. In sum, in the absence of a spot market, inflexible 100% purchase requirements set three to five years in advance would hamstring market participants, yielding inefficient outcomes.

2. **Curtailing Service To Customers Of Delinquent LSEs Is Unworkable**

The Commission's selective and phased curtailment proposal is also unworkable. At this time, it is not technically feasible to target curtailments to individual LSEs in a retail access environment. Sufficient metering, communications, and switching equipment needed to allow ITPs to make "selective" curtailments in the short time required to maintain system reliability is not currently installed on transmission and distribution systems. The cost of retrofitting such equipment, where possible, is significant.

Furthermore, emergency operations protocols are already well established, including automated load-shedding as a last resort, in accordance with accepted reliability practices of NERC and the regional reliability councils. These critical procedures should not be confused with an enforcement mechanism for failure to meet an administratively-determined resource adequacy requirement.

3. **“After-The Fact” Financial Penalties And Liquidated Damages Contracts Will Not Induce New Generation**

The NOPR suggests penalties that would be imposed at the end of the planning horizon rather than at the beginning. This approach may encourage some LSEs to risk purchasing less than their required amount of capacity if they think that the market will have sufficient capacity such that it would not be short of operating reserves. Thus, the SMD would not induce new generation or resolve the free rider issue.

The NOPR asks whether a contract with a marketer to deliver power from “unspecified resources” that includes a liquidated damages clause would satisfy the resource adequacy requirement. In our view, liquidated damages contracts do not add value unless they are backed by a qualified committed resource that is not otherwise committed to another area (and thus cannot be double-counted). If there is no resource behind the contract, paying damages after the fact does not ensure reliability.

4. **A 100% Forward Requirement Would Exacerbate Market Power Problems**

The NYPSC agrees that a forward purchase requirement would jump-start the forward market. However, a 100% forward purchase requirement such as contemplated by the SMD or the three Northeastern ISOs’ RAM Group would make the forward market vulnerable to market power since every large supplier would become a pivotal supplier whose economic or physical withholding could significantly increase prices. Imposing severe penalties on LSEs for failure to meet the forward purchase requirement forces them to buy even if the price is excessive. In any forward market, the strongest mitigator of supplier market power is the ability of a buyer to respond to an excessive forward price by deferring the purchase.

Any requirement that limits the ability of buyers or sellers to defer, especially an asymmetric requirement, such as one placed only on buyers, immediately raises market power issues. While some may argue that new entrants can be effective as market power mitigators, it is unlikely to be the case with a market design in which each year's forward capacity requirement governs just a single year's worth of the new entrant's future revenue stream (and only the capacity market part of that single year.)

For example, consider that a 2004 deadline is set for LSEs to secure their Year 2007 capacity requirement. A potential new entrant that could come on line in 2007 will make its entry decision based on a multitude of factors, including siting costs, financing costs, key risk factors such as the potential for other new plants to locate in the same market, and the firm's forecasting of the 10-to-20 year revenue streams (i.e., Years 2007 to 2026) from energy sales, ancillary services sales, and capacity sales. The Year 2007 capacity price is a small part of that calculus.

An exercise of market power in the Year 2007 capacity market, such as the withholding of 500 MW by an existing 3000 MW generating firm, for instance, could have a significant impact on the Year 2007 capacity market price.[42] Yet, this same event represents an insubstantial change in the overall multi-year economic considerations that govern a potential new entrant's entry decision. Given the small impact of a single year's capacity market revenues on the overall entry decisions of potential new entrants, it would be unwise to assume that the existence of potential new entrants would be a potent mitigator of market power in a market in which just a single year's capacity is traded.

C. <u>The NYPSC's Centralized Procurement Plan Properly Merges A Newly Designed Spot Market With A 50% Forward Purchase Obligation</u>.

1. <u>The Current Spot Market Is Flawed Because Of Its Specific Minimum Purchase Requirement</u>

The current rules for the New York capacity markets require LSEs to buy generation capacity from generation owners to cover their forecasted peak load, plus an 18% margin. LSEs that fail

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[42] The possibility of a significant impact exists because of the 100% purchase requirement. As is discussed below, if a much lower purchase requirement is established, such as 50%, no such significant price increase occurs as a result of withholding from the forward market.

to cover this margin face the potential of a very large deficiency penalty assessed by the NYISO. Sellers of capacity receive the revenues associated with the capacity market and, in return, must bid into the NYISO's day-ahead energy market every day. Similar rules govern capacity markets in the PJM Interconnection and in ISO-NE.

As is generally acknowledged, the Northeast's existing capacity market design is flawed.[43] Capacity up to the 118% level must be purchased by New York LSEs to avoid the large deficiency penalty. However, these LSEs have no incentive to purchase additional amounts because an individual LSE obtains no specific benefit from that additional capacity placed on the system in any way commensurate with the price it paid. Yet, capacity above the minimum does have value to the entire system in terms of greater reliability and lowered energy prices. The current system has lead to a boom or bust cycle in market prices. When there is only a small deficiency in available capacity, the market price is the deficiency price. When there is modest excess of supply, the market price has crashed. The NYISO is considering a deficiency value of $255 per KW-year for New York State and higher amounts for the two areas, New York City and Long Island, with locational requirements. In

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[43] See Appendix A.

contrast, recent spot market auctions for New York State, where the actual reserve margin is about 123%, have cleared at less than $10 per KW-year.

The instability of the NYISO capacity market serves neither sellers nor buyers. Sellers occasionally receive exorbitant prices for capacity but cannot count on these revenues to either finance new construction or to keep plants on line, and therefore, will only build if the more typical low prices are sufficient. While buyers usually see a low price, they do not benefit from the occasional high price they pay because that occasional high price does not necessarily drive the construction of new generation. Moreover, when the amount of excess capacity becomes low, this design encourages a large generator owner to withhold capacity in order to move the market to deficiency.

2. Implementation of a Resource Demand Curve Would Result In A Robust Spot Market

a. The Resource Demand Curve Auction

The NYPSC is working within the NYISO market participant process to fashion a "willingness to pay" Resource Demand Curve.[44] In brief, the Resource Demand Curve sets a price buyers pay that varies with the amount of capacity available at that

[44] The theoretical underpinnings of the proposal and its various elements are discussed in Appendix A.

price. As more, or less, capacity is offered, the price paid per kW gradually decreases, or gradually increases, thereby eliminating the boom or bust cycle.

Under this proposal, the ITP may procure an amount of capacity above the minimum resource level. For example, if the minimum resource level is 118% of summer peak load, but suppliers offer capacity equal to 120% of summer peak load at a low enough price, then the ITP would purchase capacity equal to 120% of summer peak load and allocate this capacity to all LSEs. Thus, each LSE would be charged the market price for capacity equal to 120% of its summer peak load. This resolves the “free rider” problem, where each individual LSE currently has an incentive to purchase only the minimum capacity because the benefits of capacity levels above the minimum are largely socialized.

The primary objective of this proposal is to reduce price volatility in the market for capacity by recognizing the value of additional capacity above minimum reserve requirements. A further objective is to reduce the vulnerability of capacity markets to the exercise of market power. A willingness to pay (demand curve) for capacity, to be applied to all LSEs via a centralized spot auction conducted by the ITP, would meet these objectives. The auction would replace the NYISO’s current “deficiency” auction and its related deficiency charge. The ITP would continue to allow self-supply of capacity via bilateral contracts and would continue to operate voluntary auctions within a spot market time frame to reveal spot prices.

b. **The Resource Demand Curve Better Represents The True Value Of Capacity To The System**

The Resource Demand Curve better represents the true value to the system, both short and long-term, of a little more or a little less capacity at or near the 118% target level. The 118% minimum reserve margin is a technical reliability requirement aimed at ensuring that outages occur no more than one day in ten years due to generation capacity shortages. However, a little more capacity has value to the market as a whole. In addition to making generation supply, as a whole, more reliable, it could result in lower energy prices with more supply available. It moderates energy price spikes, including those caused by an exercise of market power. It could also send more stable price signals that would increase investors' certainty in revenue streams.

With these benefits, the electric system should be willing to acquire more than 118% capacity reserves, when it can be obtained at somewhat lower prices than the price that would prevail at the 118% capacity level. Similarly, when reserves fall short of 118%, the system will pay a price that is higher than the annual fixed costs of a peaker to ensure sufficient capacity, but not nearly so high as the current mechanism's extremely large deficiency penalty.

A demand curve would be set high enough to ensure reasonable amounts of resources are supplied in the long run, but not so high that consumers become saddled with a large amount of expensive capacity that is not needed.[45] In the vicinity of the minimum reserve levels, the demand curve should reflect the long-run cost of capacity. This is calculated by determining the cost of building a new gas turbine and subtracting anticipated net revenues from the sales of energy and ancillary services. Balance is the key. On the one hand, a demand curve should be designed to have sufficiently shallow slopes to limit price volatility and mitigate market power. On the other hand, it should be steep enough so that the emergence of substantial excess capacity can be dampened by a falling capacity market price. It is the declining price that protects the system against the mistake of setting a demand curve that is too high and which, absent the declining price, would elicit too much capacity. In other words, the declining demand curve

[45] The ITP would review the Demand Curves periodically in conjunction with its long-term planning functions. Demand Curves would not be changed frequently; changes should only be made to address long-term imbalances.

provides a self-correcting aspect to the overall design.[46]

c. The Resource Demand Curve Would Reduce The Volatility of Capacity Spot Prices

The Resource Demand Curve would stabilize the spot market-clearing price for generation capacity since at times of modest excess supply the price for capacity will fall only slightly, rather than crash, as is the current situation. This stability would enable new merchant generation entrants and their investment bankers to more easily forecast the likely future stream of capacity market prices. Also, it will facilitate forward markets for capacity since both buyers and sellers would be able to reasonably predict the future spot market for capacity, thereby giving them confidence that the forward price they negotiate is within a reasonable range.

Extremely high price spikes in the spot market for capacity will also be moderated by the demand curve approach. Capacity price spikes occur under the current NYISO approach as the result of slight capacity shortages, whether they are true

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[46] In order to induce capacity to come on-line, the capacity market needs to provide a revenue stream to cover the annual fixed costs of a peaker that are not expected to be recovered through the energy and ancillary services markets. For example, assume that the annual (non-fuel) costs of a peaker, including return on and of investment, are $80 per kw-yr, and that the peaker can be expected to achieve energy and ancillary services market net revenues of $25 and $5 respectively. In such a case, the capacity market need not provide the full $80, but only $50.

shortages or those that result from the exercise of market power. Unreasonable price spikes can create intolerable financial problems for fledgling LSEs and for consumers.

d. The Resource Demand Curve Would Provide Strong Protection Against Market Power

Sellers exercise market power by withholding supply.[47] Withholding can drive the market price up enough to make it profitable for the withholding generator. This strategy is successful if the extra revenues a generator receives from its supply that remains in the market exceeds the lost profits associated with the supply that is withheld from the market.

The demand curve approach would establish a slope that is gradual enough to eviscerate the profitability of an attempt at exercising market power. The slope of the demand curve determines the extent to which an act of withholding will raise the price. A gradual enough demand curve can keep any such price rise small enough that generating firms, even large ones, will find it unprofitable to withhold. In other words, the extra revenues a generator would receive from its supply that

[47] Withholding is accomplished either via a reduction in the amount of capacity that participates in the market (physical withholding) or via the pricing of a portion of one's capacity so high as to price it out of the market (economic withholding).

remains in the market would not exceed the lost profits associated with its supply that is withheld from the market.

1. **A Robust Forward Market Is Also Critical To Encouraging New Capacity Resources**

The Commission correctly recognizes the importance of forward markets. Today, forward markets for capacity are purely voluntary in that neither buyers nor sellers are required to participate. Consequently, capacity forward markets are so thin that visible forward prices are lacking and are, therefore, not available to provide useful information for parties' bidding strategies.

Visible forward prices are important because they represent the market's expectation of the future spot market prices of capacity. A visible forward market price provides a valuable signal to potential new sellers regarding the potential future profitability of a decision made now to build a new plant. Similarly, a visible forward market price informs a retirement decision, which is also a multi-year decision. A buyer contemplating an investment that would reduce its purchases of electricity, such as a demand management system in an office building or an on-site generator, also relies on that information in making its decision. In addition, a visible forward market price offers a ready-made way for a small, unsophisticated player to obtain a valid forecast of possible future prices without expending the large cost needed for a detailed analysis of a future market. To the extent the forward market is liquid (that is, it contains a significant amount of purchases and sales), it yields a market-based price that provides important information to parties in conducting bilateral negotiations.

A forward market can provide a market-based advance warning of future shortages that may need to be addressed. In other words, in addition to the knowledge about the future supply/demand situation that a planner may share based on his/her forecasts, the market speaks via its forward prices and shares its average viewpoint on the same question.
However, as discussed above, exclusive reliance on forward markets would be a mistake because of market power concerns and the need to have spot markets to balance demand and supply for capacity and provide an indication that a reliability problem is developing.

2. A 50% Forward Purchase Obligation Would Yield Visible Forward Prices Without Resulting In The Exercise Of Market Power

To foster the development of forward markets for generation capacity, the NYPSC proposal contains an expectation that all LSEs would purchase 50% of their expected capacity needs three years ahead of time. To supplement bilateral activities, the ITP would hold voluntary auctions in which buyers can acquire forward market capacity from sellers. Such an auction would yield a visible price to inform the market, and would offer a place for buyers and sellers to obtain a fair market price.

The ITP would then hold a final auction to procure an amount of forward capacity to meet the forward purchase requirement of the LSEs that failed to fully satisfy the 50% expectation. This final auction would be a centralized procurement process. Many parties have noted that the presence of a centralized procurement process is critical to small LSEs when a forward purchase expectation is established. While all LSEs are free to meet the expectation with bilateral contracts or via the voluntary auctions, some LSEs may prefer to avoid firm future commitments to buy capacity. A centralized procurement process enables such LSEs to do so, by having the ITP be the procurer of forward capacity for such LSEs, and then billing the LSEs later for the cost. The NYPSC's proposed 50% forward purchase expectation contains such a centralized procurement in the form of a final forward auction.

Since only 50% of the market's generation will need to be purchased three years ahead of time, unlike the SMD's 100% approach (discussed above), it is highly unlikely that the three-year-ahead market would be vulnerable to the exercise of market power. In essence, the three-year-ahead market has a built-in 50% excess supply. There are no pivotal sellers in a market with a 50% requirement, whereas there are many such sellers in a market with a 100% requirement. Suppliers that are interested in locking in a price ahead of time will come to this market and will offer the generation capacity needed to satisfy the 50% expectation of the buyers. It would be expected that the prices in such a market would reflect both buyers' and sellers' forecasts of the future spot market that would prevail three years later. The relatively stable spot prices that the demand curve helps to create would therefore help to prevent the forward prices from being excessively volatile.

The combination of the more stable spot market for generation capacity created by the demand curve feature and the 50% forward purchase expectation will facilitate activity in forward markets for capacity. It is reasonable to expect that forward markets for the combined product of capacity and energy will also thrive, thereby accomplishing a key goal of the SMD.

V. <u>State Participation in RTO Operations</u> (SMD § IV.K.)

The NYPSC supports FERC's proposal to establish a formal role for state representatives in the ITP decision-making process. While each state is required to meet state-specific obligations, the proposed RSAC could be a convenient forum for the states to address issues of mutual concern and advise both the ITP and the Commission. Although there has been some concern that RSAC participation might be viewed as precluding the states from raising issues with the ITP, or for that matter with FERC, in other venues, the Commission could put that to rest by noting that state involvement in the RSAC should not be viewed as the exclusive forum for state communication on federal issues.

The major step that would improve the flow of electricity in the Northeast would be the elimination of export fees and wheel-through charges. Since it is unlikely there will soon be one regional RTO in the Northeast, the Commission should propose that a Northeast RSAC include state representatives from PJM, New England, and New York. We see no better way to address the rate design impacts of this barrier to efficient trade than to have the states work collectively. FERC should also make available a mediator/facilitator to work with the states on the appropriate organizational structure and on an effective dispute resolution mechanism, if necessary.

Further, although the Commission enumerates issues for the RSAC to address,[48] the states should determine which issues are most likely to result in consensus. The proposal that RSAC be involved in transmission planning is unnecessary. The National

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[48] Resource adequacy standards; transmission planning and expansion; rate design and revenue requirements; market power and market monitoring; demand response and load management; distributed generation and interconnection policy; energy efficiency and environmental issues; and RTO management and budget review. SMD NOPR at ¶554.

Governors Association's proposal would be a more effective vehicle for examining a whole host of regional issues affecting the need for and the siting of transmission lines.

A. The Commission Should Adopt the Regional State Advisory Committee

The Commission proposal to establish a RSAC, with the hope that the states in the ITP region can speak with one voice, is a step forward. The Commission's emphasis on working with the states and encouraging the states to address regional issues can only result in better decision-making at both levels. Although the states are bound to uphold state law and cannot delegate authority to a regional organization, the RSAC could facilitate coordination among states.

Because the Northeast is generally supportive of developing regional markets, a RSAC would permit states to better evaluate individual state policies against regional goals. To the extent states could reach consensus, decision-making at the state and federal level would be better informed and hopefully create a seamless regional market.

The specifics of how the RSAC would be formed and operate should be left to the regions to decide.[49] However, as with any new organization, developing a structure and dispute resolution process can be time-consuming and contentious. In the interests

[49] SMD NOPR at ¶552.

of moving the RSAC forward, a FERC staff mediator/facilitator should be made available to facilitate the organization's development.

B. **The Commission Should Consider A Northeast Region-Wide RSAC**

The SMD suggests that the ITP that operates the grid would have a regional state advisory committee. In the Northeast this could mean that there would be three RSACs; one for the PJM RTO/ITP; one for the New England ISO/ITP; and one for the New York ISO/ITP. If we are to realize the advantages of a larger regional market in the Northeast, the existing RTO/ISOs and the states must work together to overcome issues that continue to hinder a region-wide seamless market.

While each ITP may have unique issues, the major issue that would facilitate a more efficient market in the Northeast is the elimination of export fees and wheel-through charges. The best way to eliminate those fees, in a manner that would not result in unfair rate impacts, would be for the states to work together on a rate design. The Commission could facilitate overcoming this barrier to efficient electricity trade in the Northeast by encouraging a large RSAC.

C. **The States Are Best Able to Establish the RSAC Agenda**

While the Commission has identified issues on which it would seek RSAC input,[50] it may be more efficient for the RSAC itself to choose those issues where there is more likely to be consensus. Where there is no likelihood of consensus, individual states could make their own views known, as is the case today, without hampering the ability of the regional organization to move forward on areas where the potential for consensus exists.

However, there is one issue that should be removed from the RSAC agenda, which is transmission planning. The SMD seeks comment on the relationship between the National Governor's Association proposal and the RSAC. The National Governors Association Task Force on Electricity Infrastructure recommends that the Governors form an MSE to facilitate state coordination on transmission planning, certification, and siting at the regional level. Under this approach, the multiple issues relating to transmission could be analyzed and evaluated by a single entity.

With both the RSAC and the MSE addressing planning, it is possible that different recommendations and proposals would develop. The MSE would be a better forum than the RSAC to deal

[50] SMD NOPR at ¶554.

with these very complicated, contentious issues because this forum would be more effective for moving from planning to actual construction that is consistent with state siting laws. The Governors' MSE proposal makes it more likely the needed projects will be completed.

CONCLUSION

We support the implementation of SMD, with the refinements contained herein and in our November 15, 2002 comments.

Respectfully submitted,

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Dated: January 31, 2003
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APPENDIX A

Resource Demand Curve

Proposal by the New York State Public Service Commission

January 31, 2003

This document discusses the theoretical foundation of the Resource Demand Curve proposal and explains its various elements. The primary objective of this proposal is to reduce price volatility in the market for capacity resources by recognizing the value of additional capacity above minimum reserve requirements. A further objective is to reduce the vulnerability of capacity markets to the exercise of market power.

Establishing a willingness to pay (demand curve) for capacity, to be applied to all load-serving entities (LSEs) via a centralized spot auction conducted by the ITP, would accomplish these objectives. This auction would replace the NYISO's current "deficiency" auction and its related deficiency charge. The ITP would continue to allow self-supply of capacity via bilateral contracts and would continue to operate voluntary auctions within a spot market time frame to reveal spot prices.

Under this proposal, the ITP would often procure an amount of capacity above the minimum resource level. For example, if the minimum resource level is 118% of summer peak load, but suppliers offer capacity equal to 120% of summer peak load at a low enough price, then the ITP would purchase capacity equal to 120% of summer peak load and allocate this capacity to all LSEs. Thus, each LSE would be charged the market price for capacity equal to 120% of its summer peak load. This resolves the “free rider” problem, where each individual LSE currently has an incentive to purchase only the minimum capacity because the benefits of capacity levels above the minimum are largely socialized.

THEORETICAL FOUNDATION

The Role of Entry in Driving the Outcome of a Natural Market

Any businessperson knows well the importance of entry and how it drives the results of the market place. Ultimately, it is the cost of entrance that determines overall price levels and it is the amount of new entry, and exit, that determines the reliability of service seen by a buyer in the market place. If prices are high relative to the cost of new entry, then new entrants will be attracted into the market place and prices will be pulled back down. If prices are low compared to the cost of new entry, then there will be little or no new entry, exit may occur due to the inability to make a reasonable profit, and prices will be pushed up. The process of prices affecting entry, and entry affecting prices, yields an equilibrium price that is tied to the cost of entry. Over time, prices will fluctuate up and down in cycles of several years, even many years, depending on the industry, with the price gravitating toward and fluctuating around the cost of entry.

The very same process also yields a natural level of quantity, also known as reliability. It is often the relative scarcity of a product that pushes its price up, and, at the point where the degree of scarcity yields a price that is just right, i.e., equal to the cost of new entry, the natural level of reliability in that market place is established.

For example, consider the market for hotels in New Orleans. In equilibrium, hotel rooms are prevalent during off-peak periods, but are in short supply during peak periods, such as during Mardi Gras. During a peak period, prices are pushed up and the ability to obtain a hotel room is difficult, if not virtually impossible. The overall annual revenue stream of a hotel operator is greatly enhanced by high prices during peak periods, and there needs to be at least some of these high-priced peak periods (often accompanied by shortages) in order to boost the overall annual revenue stream to a level that adequately compensates the hotel operator for its annual fixed cost. In its natural equilibrium, the hotel market yields an overall annual price level that matches the cost of new entry and overall reliability level that falls out naturally as part of the market. Virtually all markets for capital-intensive products and services use this process to yield the two outcomes of price and reliability.

Why Intervene in the Electricity Market?

At the onset of electric deregulation in the United States, policymakers were concerned about whether the electric market place would naturally yield reliability levels as high as those that policymakers and electric users had grown comfortable with under the status quo. The obvious default approach was to simply let the market operate naturally, without intervention, i.e., no generation adequacy requirement and no capacity market. Under such an approach, as discussed above, entry and exit would occur and the market would reach its own natural equilibrium. The result would be energy market prices that just cover the cost of entry and a natural reliability level.[1] It is important to remember that in the wholesale electric market, as in any other market, if prices are too low to encourage new entry, the mechanism that raises prices is the lack of entry (and retirements), which tightens the market, drives up energy prices, and lowers reliability. As such, prices and reliability are the opposite sides of the same coin; to increase the former, the market needs to lower the latter.

Policymakers, at least in the Northeast, rejected the "natural" approach. Not knowing what level of natural reliability was likely to emerge, it was decided to ensure that a minimum level of reliability was maintained (an 18% reserve margin in New York, which is consistent with the one-day-in-ten-years reliability standard). Electricity was thought to require a treatment that differs from many of society's other, less crucial, products. For example, society tolerates the market's natural outcome in which several weeks a year people have to be turned away from hotels

[1] Ancillary services markets would provide an additional revenue stream, but are ignored to keep the discussion simple.

because they are sold out. It is not as acceptable to have the electric system turn electric users away with the same frequency because of electric shortages. Given this concern, the policy decision was made to intervene in the natural market place to produce an altered outcome.

Intervention does have its consequences, however. The extra generation capacity associated with a required reserve margin affects the energy market. It depresses annual energy market revenues for all generators, which in turn leads to the need for an alternative revenue stream via some kind of generation capacity payment mechanism.[2] This extra revenue stream enables the market to entice more entry than would otherwise occur, thereby, achieving the goal of enhanced reliability.

It is useful to think of a capacity market mechanism as a government-mandated “thumb on the scale” that puts more revenues into the mix for those that are supplying electricity. This is a normal policy activity for government. For example, it is akin to the policy of deductible interest on mortgages held by homeowners, which gives more money to those who choose to own a home rather than to rent one. The goal is to stimulate increased homeownership, and it works.

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[2] For a discussion of the relationship between capacity reserve requirements, energy market prices, and generation capacity payments, see Eric Hirst and Stan Hadley, “Maintaining Generation Adequacy in a Restructuring U.S. Electric Industry,” ORNL/CON-472, Oak Ridge National Laboratory, October 1999, available at www.ehirst.com.

Once a decision has been made to intervene in the market, administratively, there are two fundamental alternatives on how to do so, as follows:

1) Administratively establish a desired quantity level (at 118%, for example). With this approach, the intervention takes the form of a quantity target and the market is left to reveal the price adder that it needs in order to achieve that quantity target rather than the natural quantity that it would otherwise provide.
2) Administratively establish a price adder or a price adder formula. According to this approach, an added revenue stream is made available to all providers of capacity, the amount of that revenue stream is determined administratively, and the market is then left to reveal the amount of extra quantity it is willing to provide.[3]

In the Northeast, we chose the first of the above two options. We established a 118% capacity requirement and are letting the marketplace reveal the price it needs to achieve this government-imposed target. Based on the actual experience with this approach, discussed below, the NYPSC now recommends a switch to an alternative that works along the lines of option 2 above.

[3] This is akin to the tax deduction on home mortgages that is provided to stimulate increased homeownership.

Neither of the two intervention options is perfect, is effortless to calibrate, or allows one to avoid difficult decisions. In summary, the point of this section is that, once one has decided to reject the reliability level the market would naturally produce, and instead decides to intervene to alter that outcome, one will be faced with a challenge, will have to continually reassess the effectiveness of the intervention mechanism, and will need to make adjustments. There is no pure market-based way of intervening.

Current New York Capacity Market Design

The New York Reliability Council annually determines the minimum resource levels needed to meet the standard reliability criteria of one day's (24 hours) loss of load in 10 years. The current requirement for each LSE is to procure contracts for installed capacity (ICAP) equal to 118% of its summer peak load. Deliverability of ICAP is ensured via locational requirements. Up to 2755 MW of ICAP may be procured from regions outside New York. LSEs serving load in New York City must procure ICAP equal to 80% of their in-City summer peak load from capacity in New York City. LSEs serving load on Long Island must procure ICAP equal to 93% of their Long Island summer peak load from capacity on Long Island.

The NYISO operates forward auctions for each six-month capability period (beginning May and November), and each month also operates monthly auctions for each of the remaining months of the current capability period. These auctions are voluntary and open to all parties. The NYISO accepts supply offers and demand bids (MW and price) and ranks these by price to create supply and demand curves. In each auction, the market-clearing price is paid by all chosen LSEs and to all chosen suppliers. Locational requirements can lead to clearing prices for suppliers in New York City and on Long Island above the statewide prices prevailing in the rest of the state and can lead to clearing prices for suppliers outside New York below those prices if import limits are reached.

Prior to each month, each LSE must provide contracts to the NYISO covering its ICAP requirement for the coming month. If one or more LSE's are deficient, then the NYISO will attempt to procure the deficient quantities in a centralized deficiency auction. The NYISO enters a bid for each deficient MW at a price equal to a predetermined deficiency charge and accepts supply offers from uncommitted capacity. If a sufficient amount of capacity is offered, the needed amount is bought at the deficiency auction's clearing price, and the deficient LSEs are charged that price. If the capacity offered is less than the total deficiency, then the NYISO will charge the LSEs the deficiency charge for the remaining amounts and use the funds to attempt to procure additional capacity.

Results Of Current Market Design

In theory, one would expect the New York ICAP rules to produce very high market prices when capacity is short and very low ICAP prices when the market is in surplus. This is because the market design puts no value on extra capacity beyond the peak 118% target, while placing a very high value on capacity whenever the system is even slightly short of the target. In practice, the market has lived up to this theory, and market-clearing prices in New York have been quite volatile. There was one occasion in which the upstate ICAP market was short and cleared at the extremely high maximum value associated with the penalty, while more recently, given a roughly 5% excess (i.e., 23% reserves), the market has crashed to an exceedingly low value below $1.00/kW-month. Market participants often talk about the 118% reserve level as a cliff, and use the term "falling off the cliff" to represent what happens to price when reserves grow to exceed the target. Although the current 123% reserve margin within New York State does not seem excessive, it has nevertheless driven the market-clearing price down dramatically and undervalues the benefit of the additional reserve margin.

Therefore, the current New York ICAP market design is unsatisfactory to both buyers and sellers. It presents the prospect of a future in which ICAP prices are often low, but can't stay low and still have generators all stay in business. There will inevitably be periods in which the reserve margin shrinks, drops below 118%, and drives ICAP prices to their maximum, yielding short-term bonanzas for generators and nightmares for consumers. These would, in turn, be followed by periods in which new investment occurs yielding sufficient or excess capacity, accompanied by excessively low ICAP prices. Such a pattern of volatile prices, and volatile reliability, is not in anyone's interest.

OPERATION OF THE RESOURCE DEMAND CURVE

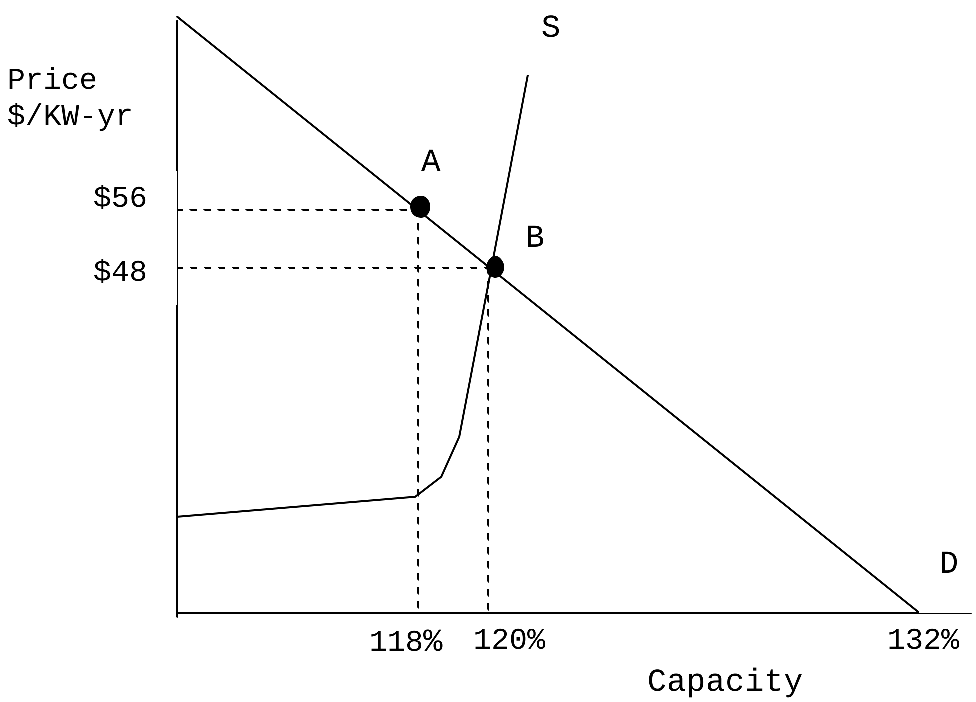
Proposed Changes

The deficiency auction would be replaced by a centralized spot auction. The buy bids that currently equal the deficiency charge would be replaced by buy bids that equal a gradually sloping Resource Demand Curve, which would be entered into the auction by the ITP. The Resource Demand Curve would be set at a level intended to encourage sufficient capacity resources to meet reliability targets. Locality requirements would continue to be recognized and may require separate, higher demand curves for New York City and Long Island. The ITP would continue its current long-term planning functions, including its annual forecast of future (20-year) load and capacity. Forecasts of impending shortages would trigger a review of the level of the demand curve. Actual resource shortages would trigger emergency measures.

Centralized Spot Auction

The ITP would operate a centralized monthly spot auction for capacity resources, replacing the current deficiency auction. In this auction, called the Demand Curve Auction, the ITP would submit demand bids for all loads in the region as a predetermined schedule of willingness to pay for capacity. By this schedule, or demand curve, the ITP would indicate a willingness to procure more than the minimum amount of capacity, but at a price that declined gradually as capacity increased. The ITP would accept offers from all qualified suppliers.[4] LSEs could self-supply by procuring supply in advance (via forward auctions or bilateral contracts) and selling into the spot auction.[5] The ITP would rank supply offers by price (from low to high) to create a supply curve. The intersection of the supply curve with the demand curve would determine the market-clearing price and quantity of capacity. All LSEs would be charged the market-clearing price for their share of the capacity. Figure 1 below depicts a demand curve auction.

Figure 1



[4] Qualified suppliers should include qualified providers of price responsive demand.

[5] This equates to the LSE selling the bilateral contract to itself; the ITP would pay the LSE the auction's clearing price for the sale, and will then charge the LSE that same clearing price for the capacity needed to satisfy the LSE's resource adequacy obligation.

The minimum reserve margin necessary to satisfy the one-day-in-ten-years criterion in New York is 18%. The annual cost of peaking capacity, less energy and ancillary services net revenues, is $56 per KW-yr. The demand curve, therefore, is established at a height such that it equals $56 per KW-yr at a capacity level of 118% of peak load (Point A). *D* is the demand curve. It is placed into the auction by the ITP. *S* is the supply curve. It represents the voluntary offers of all suppliers. The market-clearing price for capacity in this example occurs at the intersection of the demand and supply curves, at point B. The price is $48, the quantity is 120% of peak load.[6] Based on these results of the Demand Curve Auction, all LSEs are required to possess capacity rights equal to 120% of their contribution to peak load.

For example, assume an LSE has a peak load of 100 MW and contracts for 70 MW at $40 per kW-year. Suppose also that the ITP sets the Resource Demand Curve to $56 per kW-year at a quantity equal to 118% of peak load, gradually declining to $52 at 119%, $48 at 120%, etc. In the spot auction, the LSE would offer its 70 MW contract towards its resource requirement. The ITP would add this to all other resource (supply) offers to come up with a supply curve and compare this to its Resource Demand Curve. Suppose the spot auction clears (i.e., supply and demand curves cross) at a price of $48 per kW-year and quantity of 120% of peak load. The LSE is allocated a resource requirement of 120 MW and is charged

[6] The numbers used are illustrative.

for an additional 50 MW (120 MW minus 70MW) at the spot price of $48 per kW-year.

For another example, assume the LSE had contracted for 122 MW at $40 per kW-year. In that case, it would have been credited with a net sale of 2 MW in the spot auction, at the spot price of $48 per kW-year. The LSE would still own 122 MW under its long-term contract; it simply would have been compensated at the market price for providing an extra 2 MW of resources.

Setting the Resource Demand Curve

The Resource Demand Curve would be set high enough to ensure that reasonable amounts of capacity resources are supplied in the long run. In the vicinity of the minimum resource levels, the demand curve should reflect the long-run cost of capacity. An estimate of the cost of capacity is provided by the annual cost of a new combustion turbine, offset by net revenues from energy and ancillary services.[7]

Based on a preliminary analysis of the cost of new gas-fired combustion turbines in the Northeast (including a conservative, i.e., understated, estimate of net revenues from energy and ancillary services), the NYPSC estimated an annual cost of $64 per kW-year (for a generic upstate New York location). This would establish the level of the Resource Demand Curve at the NYISO's minimum resource level of 118% of summer peak load. The NYPSC has

[7] Other resources, including demand-side resources and older, inefficient generation, may be able to provide capacity at lower cost.

proposed that the Resource Demand Curve decrease at a uniform rate (straight line) to $0 at 132% of summer peak load. The gradual slope is intended to provide reasonable price stability and avoid market power problems associated with much steeper curves (the amount that price will rise in response to the withholding of supply depends on the steepness of the demand curve).

The locational requirements for New York City and Long Island would also be replaced by locational Resource Demand Curves, indicating a willingness to procure more than the minimum requirement from resources in each constrained location. For these localities, the cost of capacity may be higher; if so, the locational Resource Demand Curves would be set higher. For example, the NYISO currently requires LSEs serving Long Island load to procure resources equal to at least 93% of summer peak load from Long Island resources. The Long Island Power Authority has suggested replacing this with a separate Resource Demand Curve for Long Island, starting at a price higher than that for upstate for capacity at 93% of peak load and declining uniformly (in a straight line) to $0 at 110% of peak load.

Offsets For Net Revenues From
Energy and Ancillary Services Markets

In considering the demand curve approach it is important to acknowledge the crucial difference between it and the existing ICAP rules. The existing approach involves setting a quantity target, 118% for the statewide market, requiring all LSEs to acquire sufficient capacity to meet the requirement and enforcing it with a deficiency charge. The precision with which the deficiency charge is quantified is not terribly important. It simply serves as a deterrent to LSEs that might otherwise fail to be diligent about meeting the requirement.

In contrast, the demand curve approach requires a much more carefully estimated set of values because it involves setting a series of prices that the system will pay for specific amounts of capacity, and then letting the market reveal the quantity of capacity that is willing to commit to the system at each price. Accordingly, a demand curve that is too high will directly cause the system to pay too high a price for capacity. The opposite occurs for a demand curve that is set too low.

The demand curve approach is, to a large extent, self-adjusting since a price that is too high and elicits too much quantity of capacity will cause the price to come down as the additional quantity drives one further out and down the curve to a price that is lower than it would have been for a lower quantity. Nevertheless, unlike the existing ICAP approach, under a demand curve approach, the numbers one uses to establish the demand curve directly impact the price that is paid.

There are two key steps in developing an estimate of the price, per KW-yr, that a new generation entrant would need in the capacity market for entry to be economic. First, one must estimate the annual carrying costs of a new gas-fired combustion turbine. Second, one must estimate the expected net revenues that a new combustion turbine would earn, per year, by selling into the energy and ancillary services markets. The extent to which the net revenues from the energy and ancillary services markets fail to cover the combustion turbine's annual carrying costs becomes the basis for determining the capacity revenues that the new generator needs to receive. In other words, the price needed in the capacity market is a combustion turbine's annual carrying cost, offset by its expected net revenues from the energy and ancillary services markets.

In practical, numerical terms, it is very important to account for the energy and ancillary services markets' offsets in estimating the annual cost of new entry. Failure to account for the energy and ancillary services markets' net revenues can result in a severe overpayment to generators because the curve would be set too high.

The offsets for energy and ancillary services net revenues should be estimated based on the assumption that the electric system is exactly at its minimum required reserve margin (in New York, 18%). This estimate is frozen for purposes of setting the height of the demand curve, i.e., the estimate of the offsets does not grow or fall as a function of the actual level of reserves. If this is done, then, at a 18% reserve margin, the expected net revenues received by a combustion turbine, which equals the sum of the capacity market revenues (using the Resource Demand Curve), the energy market net revenues, and the ancillary services market net revenues, will equal a combustion turbine's estimated annual carrying charges. For reserve levels substantially in excess of the minimum required level, the above revenue streams will sum to an amount that signals potential combustion turbine entrants to stay out, at least for a while, as they are not yet needed.

Conservative Estimates Can Be
<u>Used To Assure Resource Adequacy</u>

The annual cost of new entry, net of the energy and ancillary service offsets, provides a reasonable value upon which to base the Resource Demand Curve. It sets the price point on the Resource Demand Curve at which it crosses the minimum required reserve level (118% in New York). Of course, it is prudent, from a resource adequacy standpoint, to err somewhat on the side of an overestimate of the capacity payment needed to ensure that entry of new generation becomes economic as the system's reserve margin drops down toward its minimum required level. This can be accomplished be building a slight cushion, such as a 10% adder, into the estimate of the cost of new entry. A slight overstatement causes little harm since, if new entry truly is less costly than the estimate, additional new entry will add to the system's reserve margin and move down the demand curve to the point at which the demand curve's price equals the cost of new entry. This is the self-correcting aspect of the downward sloping demand curve. The added cost to society is simply the capacity cost of a slightly larger reserve margin (a few percent), which is largely offset by the benefits of a larger reserve margin.

The economics of new entry, given the Resource Demand Curve, is worth describing briefly. Consider a situation in which load growth was occurring in the absence of new generation entry. As load growth occurs, the capacity reserve margin steadily shrinks. As the reserve margin shrinks, the expected profitability of a potential new entrant grows in two ways. First, revenue from the capacity market grows as the shrinking reserve margin causes a movement up the demand curve to a steadily higher capacity market price. Second, net revenue from the energy and ancillary service markets grows as increased tightness of these markets causes their prices to rise.[8]

As one approaches the minimum reserve level, the growth in energy market revenues becomes pronounced and, when combined with the capacity market's revenues, yields an environment in which new entry becomes profitable. One can think of the growth in energy market revenues as the key driver of entry, with the Resource Demand Curve supplementing it as it also produces ever growing capacity revenues in response to a lessening of capacity reserves.

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[8] As noted in the previous section, the energy and ancillary services markets' offsets used in establishing the Resource Demand Curve are based on an assumed level of reserves that equals the minimum reserve margin. As such, as the actual system gets tighter, the actual energy and ancillary service markets' revenues ramp up, but the offsets assumed for purposes of setting the height of the demand curve stays fixed.

Response to Capacity Deficiencies

The NYISO currently forecasts load growth and capacity additions to provide an early warning of impending shortages. Under the Resource Demand Curve proposal, tight supply conditions would automatically increase capacity prices, encouraging additional supply. In addition, the ITP could respond to persistent tight conditions by increasing the level of the Resource Demand Curve, to provide a greater cushion and avoid actual deficiencies.

In the event of an unanticipated actual deficiency, the ITP would be permitted to take emergency measures to ensure reliability. The ITP could purchase capacity or take other measures, tailored to the specific nature of the shortage (e.g., whether it was due to a few months' delay in new generation or a long-term inadequacy). The costs of these emergency measures would be charged to the appropriate LSEs, but would not set market-clearing prices. The ITP could also review the level of the Resource Demand Curve to determine if it should be increased prior to the next capability period.

An Example of Volatility Reduction

A simple numerical example can be used to demonstrate the volatility reducing properties of the Resource Demand Curve. Through this example, the spot capacity prices produced by the Resource Demand Curve are compared to the spot capacity prices produced by the current NYISO deficiency charge approach over a hypothesized 15-year period.

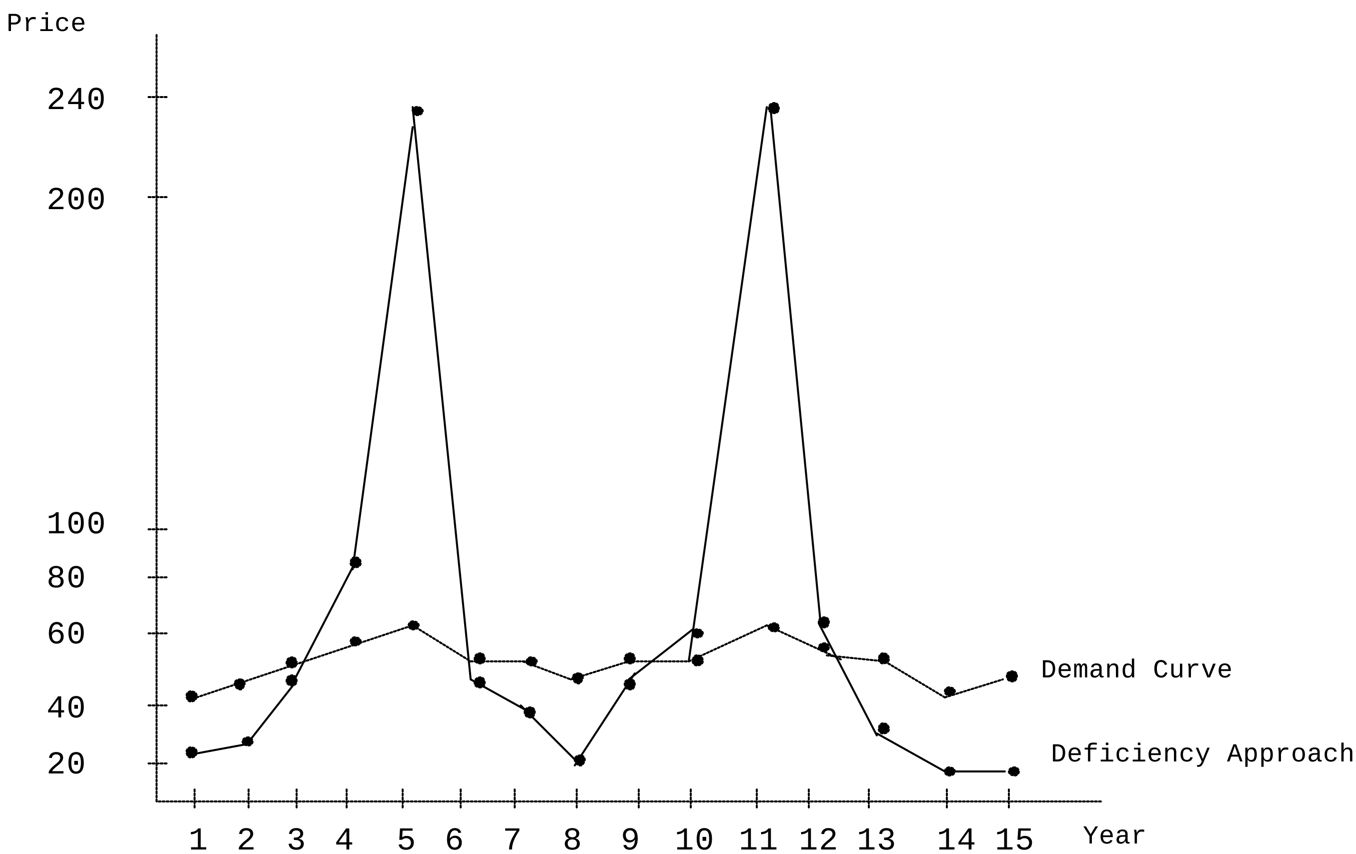
Consider a 15-year period in which there are years with large surpluses, years with modest surpluses, and years with deficiencies. The deficiency charge approach will yield extremely high capacity prices, equal to the deficiency charge, during years in which the system is deficient, extremely low prices when the system is safely in surplus, and intermediate prices for years of small surpluses. The Resource Demand Curve approach will yield prices that track the gradual slope of the demand curve; they will be higher in years of tight capacity and lower in years of surplus, but will not vary dramatically from one period to another.

Table 1 and Figure 2 compare the pattern of yearly capacity prices that would arise from the two approaches over a hypothesized 15-year period. One can see the extreme volatility of the deficiency approach, which depends heavily on an occasional extreme price spike in the capacity market to generate substantial funds. In contrast, the Resource Demand Curve approach is much less volatile and yields a more dependable capacity market revenue stream to potential new generation entrants.

Table 1

Year	Reserve Margin	Deficiency Approach's Capacity Price	Resource Demand Curve's Capacity Price
1	23%	$12	$36
2	22%	$13	$40
3	20%	$40	$48
4	18%	$80	$56
5	17%	$240	$60
6	20%	$40	$48
7	21%	$24	$44
8	22%	$13	$40
9	20%	$40	$48
10	19%	$60	$52
11	17%	$240	$60
12	19%	$60	$52
13	21%	$24	$44
14	23%	$12	$36
15	22%	$13	$40

Capacity Price Volatility: Deficiency Approach vs. Demand Curve



Example Of Market Power Mitigation
Benefit Of Resource Demand Curve

One of the concerns that has been continually raised about the current deficiency charge approach for capacity requirements is its vulnerability to the exercise of market power. With a deficiency charge that equals a multiple of the estimated annual carrying charges of a combustion turbine (three times for the NYISO), the financial benefits to a generation owner during times of deficiency are so huge that a large supplier may be tempted to artificially induce a deficiency by withholding capacity from the market.

For example, assume a situation in which the system is within 500 MWs of being deficient and capacity prices are clearing at $60 per kw-yr. A 2000 MW supplier can act competitively, i.e., as a price taker, and sell all 2000 MW at $60. Alternatively, it could withhold 1000 MW, half its capacity, and drive the price to a $240 per KW-yr deficiency charge. Such an act is profitable since the supplier sells only half as much, but at quadruple the price. This problem is caused by the sudden jump in prices inherent in the existing deficiency charge approach.

In contrast, the Resource Demand Curve, because it uses a gradually sloped demand curve, yields only modest price increases for an act of withholding. If supply is withheld, the market-clearing price moves up and to the left along the Resource Demand Curve, raising the price, but not in any dramatic way.

For example, consider the same 2000 MW supplier, under a Resource Demand Curve regime, facing a competitive price of $40 per kw-yr. If it withheld 1000 MW, which for New York State as a whole represents about a 3% reduction in reserves, the price would rise along the demand curve to $52. Since the supplier’s quantity sold drops by half, the price would have to more than double for the withholding strategy to be profitable, yet the price falls well short of doubling. The withholding strategy, therefore, is not profitable.[1]

[1] The example assumes that no costs are shed by withholding from the capacity market.

Table 2, below, shows the results of the same withholding strategy at different prices in the market, under the Resource Demand Curve approach.

Profitability of Withholding in Capacity
Market Resource Demand Curve Approach Table

Starting Price $per kw-yr	**Revenue At 2000 MW Sold**	**Price If 1000 MW Is Withheld**	**Revenue at 1000 MW Sold**	**Revenue Gain From Withholding**
52	$104 mill.	64	$64 mill.	$40 mill.
44	$ 88 mill.	56	$56 mill.	$32 mill.
36	$ 72 mill.	48	$48 mill.	$24 mill.
28	$ 56 mill.	40	$40 mill.	$16 mill.
20	$ 40 mill.	32	$32 mill.	$ 8 mill.
12	$ 24 mill.	24	$24 mill.	0
4	$ 8 mill.	16	$16 mill.	$ 8 mill.

A look at Table 2 reveals that withholding is unprofitable for a 2000 MW supplier at all market prices other than the very lowest price ranges. These low price ranges will occur only at time of large surpluses. For more normal years, the market will clear at more normal prices, and will be relatively free of market power concerns.

CERTIFICATE OF SERVICE

I, Karen Houle, do hereby certify that I will serve on January 31, 2003, the foregoing additional Comments of the Public Service Commission of the State of New York by depositing a copy thereof, first class postage prepaid, in the United States mail, properly addressed to each of the parties of record indicated on the official service list compiled by the Secretary in this proceeding.

Karen Houle

Date: January 31, 2003
Albany, New York