111 FERC ¶ 61,117
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

New York Independent System Operator, Inc. Docket Nos. ER05-428-000
and ER05-428-001

ORDER ACCEPTING ICAP DEMAND CURVES, AS MODIFIED, REMOVING REFUND CONDITION, AND DISMISSING MOTION AND REQUEST FOR REHEARING

(Issued April 21, 2005)

1. In this order, we make our findings as to the reasonableness of the parameters used by the New York Independent System Operator, Inc. (NYISO) to calculate its Installed Capacity (ICAP) Demand Curves for Capability Years 2005/2006, 2006/2007, and 2007/2008,[1] accept the proposed ICAP Demand Curves, as modified, and remove the refund condition previously imposed in this proceeding. The modifications we are making are to reduce the winter-summer differential by $1/kW/year for the New York Control Area and to reduce by $2/kW/year the net revenue offset for New York City and Long Island.[2] We also dismiss NYISO's motion for expedited action and alternative rehearing request as moot. This order benefits customers by promoting better price signals to existing and potential new market entrants for participation in the New York wholesale electric power market.

Background

2. On January 7, 2005, NYISO filed proposed tariff revisions to its Market Administration and Control Area Services Tariff (Services Tariff) to define the ICAP Demand Curves for Capability Years 2005/2006, 2006/2007, and 2007/2008. The parties' pleadings and positions regarding NYISO's proposal are described in the March 2005 Order. We will not repeat that description here.

3. In the March 2005 Order, based on the record presented, the Commission explained that it was unable to make a determination on whether to accept NYISO's proposed ICAP Demand Curve parameters or to make any of the revisions to those parameters as suggested by the intervenors. Thus, the Commission accepted for filing NYISO's proposed tariff revisions to its Services Tariff to define the ICAP Demand

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[1] The Capability Years all start on May 1st.

[2] The bases for these modifications are discussed below.

Curves for Capability Years 2005/2006, 2006/2007, and 2007/2008, and suspended them for a nominal period, to be effective March 8, 2005, subject to refund and further Commission order. The Commission explained that the proposed tariff revisions raised issues of material fact that could not be resolved based on the record before it, and accordingly, directed the Commission's Staff to convene a technical conference to obtain the necessary information.

4. The Commission directed Staff to address, at the technical conference, the appropriateness of the specific parameters to be used in calculating the Demand Curves for Capability Years 2005/2006, 2006/2007, and 2007/2008, and whether these Demand Curves would more likely elicit the entry of new generation in the market under the parameters proposed by NYISO, or under the suggested revisions of the intervenors.

5. Moreover, the Commission directed parties to be prepared to discuss and provide, among other matters, specific information concerning: (a) the appropriateness of using a 2002 load shape in the analysis conducted by Levitan & Associates, Inc. (Levitan) instead of a load shape representing normal weather patterns; (b) whether the impact of recent new capacity additions in the New York Control Area (NYCA) were reflected in the net revenue offset estimates; (c) the operating characteristics of the assumed peaking units, and their ability to participate in ancillary services and day-ahead markets, particularly given their environmental permits; (d) the appropriate capital cost and financing for the peaking units; (e) assumptions with regard to the scarcity component; and (f) the assumptions concerning local siting, such as fixed gas transportation costs and local property taxes.

6. The Commission also explained that it was particularly interested in understanding how different assumptions for these issues will affect the Annual Reference Value, and potential interdependencies between different assumptions. The Commission directed Staff to issue a notice providing additional details on the schedule and arrangements for the conference and, given the need for prompt action, directed Staff to hold a technical conference within 30 days of the date of issuance of the order. The Commission announced that it would take further action following our review of the transcript of the technical conference and materials submitted before the conference.

Notice of Technical Conference

7. Notice of Staff's technical conference and the agenda for that conference were published in the *Federal Register*, 70 Fed. Reg. 12,866, 70 Fed. Reg. 14,674 (2005).

8. The technical conference was held on March 21, 2005, and the information presented at the conference is now part of the record on which we will base our decisions on the issues.

Motion for Expedited Action/ Rehearing Request and Responsive Pleadings

9. On March 24, 2005, in Docket No. ER05-428-001, NYISO filed an emergency motion for expedited action, asking the Commission to accept NYISO's proposed ICAP Demand Curves, without any refund condition, as soon as possible, but no later than April 21, 2005. It adds, however, that for purposes of ameliorating uncertainty, the most important thing is that the Commission accept ICAP Demand Curves, at whatever level, not subject to refund, before the April 26, 2005 Spot Market Auction. In the alternative, NYISO asserts that, if the Commission cannot resolve the issues in this case by April 21, 2005, it should grant rehearing and replace the refund condition with the proposed 2005/2006 ICAP Demand Curves not subject to refund on an interim basis.

10. Keyspan-Ravenswood, LLC (Keyspan) filed comments in partial support of NYISO's motion. Keyspan states that it supports the goals behind the NYISO's March 25th filing—those being to provide certainty to the buyers and sellers in the ICAP auctions. Keyspan agrees with NYISO that the possibility of changes to the market, or refunds for settled auctions, will have unpredictable and chilling effects on the ICAP market for the important Summer 2005 Capability Period, as the NYISO described in its filing. Thus, Keyspan supports the NYISO's request for expedited action, but continues to advocate for a different Demand Curve Reference Value, as outlined in its prior filings and at the March 21, 2005 Technical Conference.

11. Independent Power Producers of New York, Inc. (IPPNY) filed answer in support of NYISO's motion. IPPNY asserts that the benefits of the Demand Curves will be lost if the Commission does not expeditiously approve the Demand Curves without a refund condition. IPPNY further states that, if the Commission cannot approve ICAP Demand Curves by mid-April, IPPNY supports the NYISO's request that the Commission grant rehearing and make the proposed 2005/2006 ICAP Demand Curves effective, without a refund condition, for 60 days, starting on March 9, 2005. It points out that removing the refund condition would allow the NYISO to conduct the next several ICAP auctions free from uncertainty and would provide the Commission with additional time to reach a decision.

12. A group of intervenors[3] filed a response in opposition to NYISO's motion. It maintains that NYISO failed to justify its proposed Demand Curves and that they should be rejected until such time as NYISO performs the necessary supporting analysis. It argues that the existing Demand Curves should continue to be used in the meantime.

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[3] Comprised of New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation, Long Island Power Authority (LIPA), Multiple Intervenors (identified in the March 2005 Order), and Municipal Electric Utilities Association of New York (MEAU) (collectively, Indicated NY Entities).

13. IPPNY filed a motion requesting that the Commission reject the Indicated NY Entities' response, because its detailed arguments and expert testimony is nothing more than a thinly veiled, impermissibly late attempt to supplement the record.

Discussion

14. We will accept the proposed ICAP Demand Curves, as modified below, to be effective March 9, 2005 (as provided in the March 2005 Order) and remove the refund condition established in the March 2005 Order. Given the timing of our issuance of this order, NYISO's revised Demand Curves will be in place prior to the April 26, 2005 Spot Market ICAP Auction. This being the case, and given our finding that the Demand Curves, as modified, will result in rates that are just and reasonable, no refunds will be necessary or appropriate.

15. In addition, given our issuance of this order, and our findings herein, we will dismiss NYISO's motion and request for rehearing as moot.

16. To assist in an understanding of the issues discussed below, we provide a brief summary of the derivation of the ICAP Demand Curves at issue in this proceeding. As we explained in the March 2005 Order,[4] Demand Curves are derived from: (a) a point defined by the minimum ICAP requirement (118 percent of load) as set by the New York State Reliability Council, and the cost of new peaking generation (the "Annual Reference Value"); and (b) a point at which the ICAP requirement declines to zero ("Zero Crossing Point") that reflects the declining value of capacity reserves and an appropriate slope for the Demand Curve.[5] The Annual Reference Value is determined by an estimate of the annual capital and fixed operation and maintenance costs, including a return on investment, to construct a typical new peaking unit (*i.e.*, a simple cycle gas turbine plant), less an offset for projected energy and ancillary services revenues, net of variable operating costs, that a new peaking unit could expect to earn in the New York markets.

A. Capital Costs and Related Parameters

1. Capital Cost of New Turbine

17. NYISO's consultant, Levitan, developed the Annual Reference Value based on the annualized cost of a peaking generating unit. Levitan determined that a 7FA gas turbine was the appropriate technology for NYCA and the LM6000 gas turbine was the

[4] March 2005 Order, 110 FERC ¶ 61,201 at P 19.

[5] The Demand Curves also continue upward to the left until they reach a value of 1.5 times the fixed costs of a new peaking unit, thus establishing the maximum deficiency charge for LSEs that are below the minimum ICAP requirement. This feature is not changed by the proposed revisions to the Demand Curves.

appropriate technology for New York City and Long Island. [6] The Levitan analysis estimated that the capital cost of a LM6000 gas turbine plant in New York City and Long Island would be $1,189/kW and $1,126/kW, respectively. The estimated capital cost of a 7FA gas turbine plant in NYCA would be $599/kW. These capital costs produce annual fixed costs of $87/kW-year for NYCA, $176/kW-year for New York City, and $155/kW-year for Long Island.

18. Multiple parties, particularly parties representing Rest-of-State interests, argue that the assumed capital cost for the 7FA gas turbine is too high. The primary criticisms of the Levitan Rest-of-State estimate are that it is not based on actual turbine installations within New York, that it is based on vendor quotes, and thereby "does not reflect all discounts that a buyer ready to actually purchase the turbine would receive,"[7] and that it is higher than estimates from neighboring regions. Indicated NY Entities further argue that "the glut of equipment in the supply market was ignored."[8] Although NYPSC supports the annualized fixed cost estimate of $599 for NYCA of NYISO, it argues that the appropriate value is even lower, based on its analysis of a new combustion turbine installed by the Jamestown Board of Public Utilities.

19. Keyspan argues that the 96 MW net capacity used by Levitan for LM6000 units in New York City is too high, and that an alternative value of 91 MW should be used instead. The 91 MW capacity value is based on a generation-weighted average summer net capacity instead of the 59 degrees F basis used by Levitan. Keyspan's rationale for using the generation-weighted average summer net capacity value is that most of the revenue from the operation of the LM6000 unit will be derived from summer operation and the Demand Curves is based on summer peak loads.

20. Indicated NY Entities raise a broader point about the selection of peaking generation units to serve as the entry technology. In its protest, Indicated NY Entities questioned whether NYISO used the correct entry technology in its analysis when it developed cost for peaking units. Indicated NY Entities argue that NYISO did not conduct a sufficient comparison of other generating technologies, such as combined-cycle facilities, to determine the proper entry technology.

[6] The 7FA and LM6000 gas turbines are specific models of gas turbines manufactured by General Electric.

[7] Comments of Steven Keller, New York Public Service Commission (NYPSC), March 21 Technical Conference, tr. at 25, lines 3-5.

[8] Comments of Michael Mager, Indicated NY Entities, March 21 Technical Conference, tr. at 30, lines 10-11.

Commission Conclusion

21. The Commission finds that the NYISO capacity cost estimate is reasonable. The development of capital cost estimates requires reliance on estimates drawn from recent installations or vendor quotes. Although it is preferable to base capital cost estimates on recent installations -- in a similar location -- of the same turbine, if possible, it is not always possible to find such a unit. In the instant case, there was no such comparable installation. In these circumstances, we find that NYISO's use of a recent installation of a 7FA turbine in the Midwest as the basis for the capital cost estimate to be more appropriate than extrapolating the costs of a different turbine model in a different plant configuration.[9] The response of Seth Parker of Levitan to the use of the Jamestown plant at the March 21 Technical Conference echoes our concerns with using the alternative capital cost estimated by NYPSC:

> The unit was installed in combined cycle model where there was an HRSG, a heat recovery steam generator tied into an existing steam turbine. And trying to take those costs and figure out what should be included, what should be discarded, some in between line items to make it appropriate for a simple cycle plant is a process that's so difficult it renders the entire approach in our opinion inappropriate.[10]

22. We also disagree with the arguments raised by the NYPSC and others that Levitan's estimate is too high because it relied on vendor quotes.[11] The capital cost estimates are intended to reflect equilibrium conditions. Consequently, it would not be prudent to assume the existence of discounts because this would imply foreknowledge of the market for turbines. The reasonableness of Levitan's estimate is further supported by the fact that estimates by ISO New England (ISO-NE) of the cost of building a new turbine in New England are similar to that of Levitan.

23. The Commission finds that NYISO used the appropriate capacity value for the New York City LM6000 units. According to Levitan, it "calculated net capacity and net heat rate at 59° F, *i.e.*, standard ISO conditions, and at 25° F winter temperature and

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[9] Protesters proposed to use the analysis conducted by NYPSC. NYPSC used the costs of installing a single-turbine application of LM6000 turbines in a combined-cycle configuration at the Jamestown Board of Public Utilities as the basis for the costs of a hypothetical dual 7FA turbine.

[10] Comments of Seth Parker, Levitan, March 21 Technical Conference, tr. at 55, lines 11-18.

[11] The strength of this argument was undermined by the contradictory comments attributed to Jamestown at the March 21 Technical Conference. *See* tr. at 55 to 56 and at 62.

90° F summer temperature for dispatch simulation modeling purposes."[12] The use of standard conditions to measure capacity is a reasonable and accepted approach, and ensures that capacity alternatives are examined on a comparable basis. Moreover, as Levitan states, it appropriately adjusted for temperature when it conducted its dispatch simulation – thereby considering seasonal variations noted by Keyspan.

24. We agree with NYISO that it is appropriate to use the cost of a new peaking technology as the basis for the capacity cost estimate, rather than that of another technology with higher fixed costs and lower variable costs, such as a combined-cycle facility as Indicated NY Entities proposes to consider. The use of peaking technology is in keeping with standard approaches to estimating the marginal cost of capacity.[13]

25. Moreover, a peaking unit can typically meet the incremental capacity needs satisfied by an ICAP requirement at a lower cost than other technologies, and the Annual Reference Value should reflect the lowest-cost way of procuring this incremental capacity. The purpose of an ICAP requirement is to ensure a minimum amount of capacity in the market to promote reliability, and thus, to elicit additional capacity that might not otherwise enter the market. This additional capacity would typically be needed to operate at a lower load factor than other capacity in the market, since the additional capacity would be needed to serve load and ancillary service requirements only when the amount of other market capacity was insufficient to do so. The lowest-cost way of meeting a low-load-factor load is typically from a peaking unit with low fixed costs and higher variable costs. Meeting a low-load-factor load with units with higher fixed costs and lower variable costs would typically result in higher per MWh costs because their higher fixed costs are spread over only a few MWh of load.[14]

2. <u>Financing Assumptions</u>

26. In its development of the annualized fixed costs of the peaking technologies, Levitan assumed the following assumptions about how the power plant would be financed: an inflation rate of 3 percent, construction debt rate of 5 percent, permanent debt rate of 7.5 percent, permanent debt term of 20 years, debt/equity ratio of 50/50, an after-tax equity rate of return of 12.5 percent, and a useful plant life of 20 years.

[12] Affidavit of Seth Parker at 6 (P 18).

[13] See, for example, National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, which uses peakers as the basis for marginal capacity costs.

[14] Units with higher fixed costs and lower variable costs can meet higher load factor loads at lower unit costs, because their higher fixed costs can be spread over a larger amount of load.

27. Several protesters argue that the financing assumptions used by Levitan did not reflect how a merchant peaking plant would be actually financed. In particular, protesters argue that the 20-year length of capital recovery period for the new combustion turbines was too long, and the assumed return on equity was too low. Keyspan argues that a 15-year term would be more appropriate, based on the fact that the Internal Revenue Service (IRS) uses a 15-year depreciable life for peaking plants, that the investment community has widely accepted a 15-year life for financing peaking plants, and that there is investment risk associated with capital recovery under the ICAP market for peaking plants.[15] IPPNY and NRG[16] support Keyspan's protest on the appropriate financing period.

28. IPPNY argues that Levitan's assumed after-tax return on equity of 12.5 percent was too low, and that the resulting weighted average cost of capital that results (8.5 percent) does not reflect the cost of capital for a merchant project. IPPNY also points out that the Commission has recently authorized a higher 12.8 percent for New England transmission owners and set for hearing aspects of an incentive program that could boost that return on equity to 14.3 percent. IPPNY asserts that the return on equity appropriate for a merchant generation investment should significantly exceed that available to a regulated, rate-based transmission investment.

29. NYISO's consultant, Levitan, defended the financing assumptions as reasonable. According to Seth Parker of Levitan, "[Levitan's] assumption of a twenty year capital recovery period is consistent with my personal experience, with the permanent debt term, and with the IRS classification of gas turbines as 20 year property (asset class 49.15) with a 20 year recovery period."[17] Levitan also challenged Keyspan's reference to tax depreciable life as support for 15-year recovery as selective and "ignores the IRS classification as 20 year property."[18] Levitan defended the 12.5 percent return on equity assumption as appropriate under equilibrium conditions and "the rates would be what I

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[15] Seth Parker of Levitan further elaborated at the March 21 Technical Conference on the process that Levitan used to derive the financing assumptions: "We took the data that tended to be clustered in the middle for a merchant plant that didn't necessarily have a PPA or that type of credit support from a utility and balanced it against what a plant in the real world with the demand curve mechanism in place would really require to make the equity investors comfortable." March 21 Technical Conference, tr. at 86, lines 5 to 10.

[16] "NRG" refers to NRG Power Marketing, Inc., Arthur Hill Power LLC, Astoria Gas Turbine Power LLC, Dunkirk Power LLC, Huntley Power LLC, and Oswego Harbor Power LLC, collectively.

[17] Affidavit of Seth Parker at 18 (P 42).

[18] *Id.*

would call compensatory where there would be not a surplus or a deficiency of capacity, but just about the right amount."[19] Levitan also notes that its return on equity assumption was very close, and slightly higher, than values used by PJM Interconnection (PJM) and ISO-NE in similar exercises.

30. Indicated NY Entities support the use of 20 years as reasonable. Indicated NY Entities bases their support for 20 years on the following points: the useful life of a generator is at least 20 years, and that PJM and ISO-NE are also using a 20-year life in their financing analyses. NYPSC supports the 20-year recovery period and the 12.5 percent return on equity value, and used NYISO's assumptions in its own alternative capital cost estimates. NYPSC further stated that Levitan's financing assumptions are "reasonable in order to determine the annual capital costs to build a merchant power plant at a time when there is no excess capacity."[20]

Commission Conclusion

31. We find that NYISO's use of a 20-year recovery period is reasonable for the reasons stated by Mr. Parker of Levitan and the Indicated NY Entities, *i.e.*, typical useful life, length of permanent debt term, and the fact that the other RTOs use the same financing period. We also find that Keyspan's arguments for a shorter recovery period are not persuasive for three reasons. First, it is not appropriate to base useful life on IRS depreciation schedules, as these schedules reflect tax policy considerations, not the appropriate period for useful life and capital recovery. Second, Keyspan has not provided any support for its contention that the "investment community has widely accepted a 15-year life for financing peaking plants." Finally, the use of a 20-year recovery life assumption by the NYPSC, PJM, and ISO-NE further supports NYISO's selection of 20 years as a standard and reasonable assumption that is in general use.

32. Similarly, we find that the assumed after-tax return on equity of 12.5 percent is reasonable for the reasons stated by Levitan. Except for general arguments that merchant plants would require higher returns on equity, protesters did not provide an alternative return on equity nor any detailed analysis of the deficiencies of Levitan's return on equity. The point about higher authorized returns on equity on transmission investments by IPPNY is not germane to the facts of this case, and does not address the relative riskiness of merchant plant investments under equilibrium conditions. Finally, as we found with the financing period above, the use of similar return on equity by NYPSC, PJM and ISO-NE provides further support that Levitan's return on equity assumption is reasonable.

[19] Comments of Seth Parker, Levitan, March 21 Technical Conference, tr. at 87, lines 13-15.

[20] Affidavit of Jeffrey Hogan and Steven Keller, NYPSC, at 6 (P 21).

3. Miscellaneous Fixed Costs

33. As part of its development of the costs and characteristics of the hypothetical peaking units, Levitan analyzed and prepared estimates of local costs such as property taxes and gas transportation costs. For property taxes, Levitan assumed property taxes for a new LM6000 gas turbine of approximately 2 percent of capital costs based on an evaluation of property tax levels. For local gas transportation, Levitan assumed that generators can negotiate with local distribution companies (LDCs) to avoid minimum bill provisions. Local transportation charges paid to LDCs for Rest-of-State are estimated to be $0.26/MMBtu during the heating season and $0.10/MMBtu during the non-heating season. For New York City and Long Island, Levitan estimated local transportation charges of $0.19/MMBtu on a year-round basis.

34. Keyspan and NRG challenge the estimates prepared by Levitan. On property taxes, Keyspan and NRG argue that Levitan should have used the higher effective rate of 5.59 percent for specialty property tax like gas turbines. On local gas transportation, Keyspan and NRG argue that fixed natural gas transportation costs applicable to new and existing gas peaking facilities located in New York City were erroneously omitted from the Levitan Report, and that Levitan's assumption that generators can negotiate a bypass agreement was optimistic and potentially unrealistic. Consolidated Edison of New York, Inc. (Con Ed) supports Levitan's assumptions and argues that Levitan's analysis correctly reflects the variability and negotiated nature of both property tax and local gas transportation costs.

Commission Conclusion

35. We find that the assumptions made by Levitan on property tax and local gas transportation costs are reasonable for the reasons stated by Levitan and Con Ed. The protesters argue that flexibility and negotiated rates should not form the basis for assumptions, and full cost levels for these assumptions should form the basis for the costs in order to be realistic. We disagree, and find that Levitan appropriately analyzed past experience and costs to develop a reasonable estimate of property tax and local gas transportation.

B. Net Revenue Offset

36. As noted above, NYISO proposes an Annual Reference Value for the ICAP Demand Curves in each of the three ICAP zones. The Annual Reference Value in each zone is the annualized cost of a peaker in the zone minus expected net revenues that a peaker would be expected to receive in the zone. NYISO proposes this net revenue offset to be $15/kW-year for the Rest-of-State (plus a $5/kW-year adjustment to reflect differences in generation capacity availability in winter versus summer), $50/kW-year for New York City, and $40/kW-year for Long Island.

37. NYISO's quantitative proposal is based on analysis by its consultant, Levitan, with adjustments based on analysis from NYISO's Independent Market Adviser, Dr. David Patton. Levitan used a chronological dispatch simulation model to forecast the net energy and ancillary service revenues that a peaker would likely earn over 20 years, assuming a 2002 load shape.[21] The load shape was adjusted in every year so that the system peak loads and annual loads matched the forecast values under normal weather conditions in the 2004 Load and Capacity Data Report (also known as the "Gold Book") prepared by NYISO. Levitan also included all known near-term generation additions and retirements. Levitan conducted simulations where load was treated "deterministically," that is, where real-time load was assumed to be known with certainty at the time of day-ahead unit commitment. Levitan also conducted simulations where load was treated "stochastically," that is, where real-time load differed randomly from the day-ahead forecast used for unit commitment. The effect of such stochastic variations from day-ahead forecasts is to increase the dispatch of peakers in real-time, and thus, their revenues.[22] NYISO reports that Levitan's estimated net revenue for the Rest-of-State was $1 to $2 per kW/year under the deterministic simulations and $8 to $10 per kW/year under the stochastic simulations.[23]

38. In formulating its filed proposal, NYISO made some adjustments to the Levitan estimate of expected net revenues to reflect several factors. NYISO concluded that the early years of the Levitan stochastic simulations did not reflect tight market conditions, and that the study did not reflect the price volatility that would likely occur during unexpected intra-hour events such as generator or transmission outages. Thus, NYISO concluded that its proposed estimate for the net revenue offset should lie between the deterministic and stochastic results, plus an additional amount reflecting expected revenues during scarcity conditions. NYISO relied on an analysis by Dr. Patton that estimated average annual scarcity revenues of $10 per kW-year, which reflects scarcity conditions averaging 20 hours per year. In NYISO's view, this scarcity revenue estimate is reasonable for a marginally tight market with a slight capacity excess. Based on these considerations, NYISO proposes a net revenue offset (reflecting both non-scarcity and scarcity conditions) of $15 per kW-year for Rest-of-State (plus an additional $5 per kW-year to reflect differences in generation capacity availability in winter versus summer, to be discussed below), $50 per kW-year for New York City, and $40 per kW-year for Long Island.[24]

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[21] *See* Affidavit of Seth G. Parker at 12-15.

[22] For example, the average capacity factor of peakers in New York City in 2005 was 15 percent in the deterministic simulation, compared with 19 percent in the stochastic simulation.

[23] *See* Joint Affidavit of Belinda F. Thornton and John W. Charlton at 17.

[24] *Id.* at 18.

39. Several intervenors argue for different net revenue offsets. Generators argue that NYISO's proposed net revenue offsets are too large (and thus, that the resulting Annual Reference Values are too low). Conversely, those representing loads argue that NYISO's proposed net revenue offsets are too small (and thus, that the resulting Annual Reference Values are too high). The alternative recommendations for the net revenue offset for each zone are summarized in the following table:

Alternative Recommendations for Net Revenue Offset ($ per kW-year)			
Party	***Rest-of-State***	***New York City***	***Long Island***
NYISO	$20	$50	$40
City of New York		$50-60	
Indicated NY Entities	$22		
NYPSC	$12.50		
IPPNY	$10		
Keyspan		$25-$30	

40. In reaching their conclusions, intervenors criticize several aspects of NYISO's analysis underlying its proposal, including the integral issues of load shape, the Annual Reference Value and new capacity additions, scarcity component, winter-summer differential, LM6000 gas turbine heat rate, and ancillary service revenues.

Commission Conclusion

41. As discussed below, we are not persuaded by intervenors' criticisms on these issues, except for the issue of ancillary service revenues in New York City and the winter-summer differential for NYCA. Thus, we will accept NYISO's proposed net revenue offsets for the three ICAP zones, with two adjustments. We conclude that NYISO's proposed offsets, with the two adjustments, are just and reasonable and reflect the expected revenues that a peaker is likely to receive when supply conditions are near, but slightly higher than, the minimum capacity requirement. As discussed below, we agree with NYISO and others that the offsets should reflect expected revenues at this level of supply. Regarding the winter-summer differential, we conclude that NYISO's proposal should be reduced by $1 per kW-year for NYCA, and thus, a NYCA net revenue offset of $19 per kW-year (*i.e.*, $1 per kW-year less than NYISO's proposal) is reasonable. We agree with intervenors that LM6000 gas turbine peaking units in New York City are not likely to receive the approximately $2 per kW-year of revenues for providing ten-minute non-spinning reserves underlying NYISO's proposed net revenue offset for New York City and Long Island. Therefore, we conclude that a net revenue offset for New York City of $48 per kW-year (*i.e.*, $2 per kW-year less than NYISO's proposal) is reasonable. Finally, we conclude that NYISO's proposed net revenue offset of $40 per kW-year for Long Island is reasonable.

1. Load Shape

42. As noted above, the Levitan study relied on a 2002 load shape. Keyspan argues that the 2002 load shape distorts the estimate of net revenues because it does not reflect an average load shape for load in New York State, *i.e.*, that 2002 had more near peak hours than the average.[25] Since peakers tend to earn most of their energy and ancillary service revenues during peak and near peak hours, overstating the number of these hours would tend to overstate net revenues. Keyspan recommends a weather-normalized load shape based on the 1993-1997 period. Con Ed supports the 2002 load shape. It argues that the weather in 2002, as reflected in the combination of heat, humidity and total cooling-degree days, is average.[26] NYPSC also favors the 2002 load shape. It argues that, while the 2002 load shape may have more peak hours than the historical average, it is likely to be representative of load shapes in the future, because increased real-time pricing at the retail level will flatten the load shape.[27] Levitan defends its use of the 2002 load shape. It states that the Installed Capacity Subcommittee also adopted the 2002 load shape instead of the previously used 1995 load shape, because the "average curve" derived from 1993-2002 relies on antiquated data and does not reflect current structural changes.

Commission Conclusion

43. We conclude that using the 2002 load shape is reasonable for the reasons stated by Levitan, Con Ed, and NYPSC, *i.e.*, that the 2002 load shape represents average weather, that the use of a more recent load shape is preferable, and the potential impact of real-time pricing on future load shapes. While the 2002 load shape may differ from the historical average, we agree with NYPSC that the relevant issue is whether the 2002 load shape is representative of the future, and we think it is. The 2002 load shape is likely to better reflect current structural changes in the market than historical averages from the 1990s; indeed, as Levitan notes, the Installed Capacity Subcommittee has adopted the 2002 load shape in preference to averages from the 1990s for this reason. Also, as NYPSC notes, increased use of real-time pricing at the retail level may flatten the load shape in the future.

2. The Annual Reference Value and New Capacity Additions

44. Panelists at the March 21 Technical Conference discussed what level of supply (relative to the minimum capacity requirement) should be assumed in estimating the amount of energy and ancillary service revenues to include in the net revenue offset. As discussed above, Levitan's estimate started with the existing stock of capacity, adjusted

[25] Statement of Madison Milhous at March 21 Technical Conference, tr. at 132.

[26] Statement of Norman Mah at March 21 Technical Conference, tr. at 108.

[27] Affidavit of Mark A. Reeder at 13.

for all known near term generation additions and retirements. Dr. Patton noted that recent generation additions and mild weather have led to surplus conditions currently.[28] Several Technical Conference panelists, including Mr. Reeder (for NYPSC), Dr. Patton (the NYISO Independent Market Adviser), and Mr. Charlton (for NYISO), argued that the net revenue offset should reflect revenues expected during relatively tight market conditions, when generation capacity is at or near the minimum capacity requirement, and that capacity additions above this level should not be considered.[29]

45. Mr. Reeder and Dr. Patton recommended that the net revenues should be those associated with capacity that is slightly greater (by perhaps a couple of percentage points) than the minimum capacity requirement. The reason they give is that capacity relative to the capacity requirement will naturally fluctuate over a range. Mr. Reeder and Dr. Patton argued that the Demand Curves should be developed so that market incentives will encourage aggregate supply that avoids dipping below the minimum capacity requirement. Mr. Younger (for IPPNY) argued for an offset associated with supply somewhat greater than the minimum capacity requirement. Mr. Wallach (for New York City) commented that the objective should be to avoid a market that is chronically short, although he had concerns with whether the Demand Curves would promote new investment efficiently. Mr. Kinney (representing transmission owners, but speaking for himself on this issue) offered an alternative view – that the market should sometimes be allowed to go short, below the official minimum capacity requirement of an 18 percent reserve margin; he referred to a study that concluded that a 16 percent reserve margin would satisfy the statewide reliability requirement, if combined with increases to the locational requirements in New York City and Long Island.

Commission Conclusion

46. We will accept NYISO's proposed net revenue offsets for the three ICAP zones. NYISO's proposed offsets reflect the expected revenues that a peaker is likely to receive when supply conditions are near, but slightly higher than, the minimum capacity requirement. We agree with NYISO and others that the offsets should reflect expected revenues at this level of supply. The ICAP Demand Curves should create incentives for capacity investment not to fall below the minimum requirement established by the New York State Reliability Council, the organization responsible for setting the minimum requirement.

47. We expect that, under the Demand Curves, capacity will tend toward the level where prices on the Demand Curves match the costs of peaking capacity net of energy and ancillary service revenues. However, capacity as a percentage of peak demand will naturally fluctuate over time on either side of this level as short-term market conditions vary. If the net revenue offset were to reflect energy and ancillary service revenues

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[28] Affidavit of David B. Patton, Ph.D., at 4.

[29] *See* March 21 Technical Conference, tr. at 162-183.

expected when supply conditions were precisely at the minimum capacity requirement (or at a smaller supply level, as Mr. Kinney advocates), capacity would likely fall below the minimum during some periods.

48. To avoid this result, the net revenue offset should reflect energy and ancillary service revenues expected when supply is modestly greater than the minimum requirement, so that capacity is less likely to fall below the minimum requirement as capacity conditions fluctuate over time. On the other hand, the net revenue offset should not be based on supply conditions that are significantly greater than the minimum requirement, to avoid imposing excessive capacity costs on customers. Consequently, we find that the approach taken by NYISO to set the net revenue offset at a modestly greater than the minimum requirement is appropriate.

3. Scarcity Component

49. NYISO proposes to include \$10/kW-year of revenues from sales of energy in each ICAP zone during periods of scarcity. NYISO's proposal is based on an estimate by Dr. Patton of the likely scarcity revenues during years when the supply is slightly greater than the minimum capacity requirement (by one or two percentage points).[30] Dr. Patton estimated scarcity revenues of \$10 per kW-year, based on an assumption of 20 hours of shortages per year and a shortage price of \$1000/MWh in these hours. Dr. Patton notes that the actual net revenue associated with shortage hours over the 2000-2003 period ranged between about \$6 and \$15 per kW-year. Mr. Charlton of NYISO stated at the March 21 Technical Conference that the Levitan stochastic analysis estimated up to 30 hours of scarcity in an equilibrium condition, and that assuming 20 hours of scarcity (as Dr. Patton assumed) was a way to develop scarcity revenues associated with supply that was modestly greater than the minimum capacity requirement.

50. Several protests were raised about the size of the scarcity component. Mr. Wallach, representing the City of New York, expressed concern that Dr. Patton's analysis underestimated scarcity revenues – that the number of scarcity hours is likely to be greater than 20 hours, since Levitan's stochastic analysis estimated a larger number (30 hours).[31] Mr. Kinney, representing Indicated NY Entities, stated that the number of scarcity hours could be as high as 60. He also argued that the energy prices forecasted by Levitan during both scarcity and non-scarcity conditions understate the prices that are likely to occur, based on a comparison of over-the-counter (OTC) broker quotes of what the market is expecting in the near future.[32]

[30] March 21 Technical Conference, tr. at 171.

[31] March 21 Technical Conference, tr. at 113.

[32] Indicated NY Entities' Protest at 12. (Indicated NY Entities' Protest states that OTC prices for 2005 and 2006 for Zones G, H and I are about \$12 to \$15 per MWh higher than the prices estimated by Levitan).

Commission Conclusion

51. We conclude that NYISO's proposal to incorporate Dr. Patton's estimate of $10/kW-year for revenues under scarcity conditions is reasonable. Dr. Patton's estimate is based on an average of 20 hours of scarcity hours per year. While Levitan forecasts 30 hours of scarcity per year, it is reasonable to base the Annual Reference Value on Dr. Patton's modestly smaller number of 20 hours. That is because the Annual Reference Value should reflect net revenues that would occur when capacity is modestly greater than the minimum requirement, and increasing capacity beyond the minimum requirement would reduce the number of hours of scarcity. In addition, Dr. Patton's estimate lies near the midpoint of the range of actual annual net revenues (*i.e.*, $6 to $15 per kW-year) associated with shortage hours over the 2000-2003 period. Mr. Kinney, representing Indicated NY Entities, argues that Dr. Patton's estimate significantly understates scarcity revenues and states that the number of scarcity hours could be as high as 60. However, Mr. Kinney provides no support for the 60 hour estimate. Indicated NY Entities also point to the fact that over the counter (OTC) broker quotes have been higher than Levitan's estimated prices as support for their conclusion that NYISO has understated net energy revenues. However, we agree with the comments of Mr. Younger at the March 21 Technical Conference that there is not enough information about OTC broker quotes to reach the conclusions suggested by the Indicated NY Entities.[33] For example, the Indicated NY Entities do not state what quantities of energy were associated with the quotes or whether there were any consummated contracts associated with the quotes. Also, the quotes are described as average annual prices, while the revenues associated with peakers would come from prices in only a few, high-priced hours.

4. Winter- Summer Differential

52. NYISO points out that, since their inception, the ICAP Demand Curves have incorporated an adjustment to account for the greater potential supply of capacity in the winter than in the summer that results from generators being capable of higher output in the winter, primarily because of the lower ambient temperatures. NYISO explains that the Demand Curves are adjusted upward so that the resulting summer and winter capacity prices will, on average, equal the Annual Reference Value. NYISO adjusted the Annual Reference Value by the ratio of winter to summer aggregate capacity, as provided in the 2004 Load and Capacity Data report (Gold Book).

53. NYISO points out that as the Demand Curves were initially implemented, adjusting by the Gold Book ratio only recognized changes in the capability of internal generation, and did not consider any seasonal effects related to imports or exports of capacity. NYISO therefore made an additional adjustment to reflect the fact that the

[33] March 21 Technical Conference, tr. at 209.

Gold Book data overstates the actual seasonal difference in capacity available to and clearing in the NYCA capacity auctions. This additional adjustment is the "winter revenue benefit."

54. NYISO proposes to increase the revenue offset by $5 per kW/year to reflect a decrease – and resulting upward price pressure – in capacity imports during the winter, particularly from Canada. NYISO claims that over the past two winters actual winter imports have been less than summer imports and NYISO expects this trend to continue. NYISO notes that since the Canadian systems are winter-peaking the quantity of capacity that they can reliably export in the winter months is reduced. Since it expects this trend to continue into the sustainable future, NYISO concludes that it is reasonable to recognize a winter revenue benefit in the Demand Curves.

55. NYISO notes that the Gold Book data suggested approximately 1,400 MW of additional capacity that should be available in the NYCA market in the winter capability period as compared with the summer capability period. NYISO estimated that for each decrement of 110 MW of actual supply participation in the ICAP markets below the 1,400 MW seasonal performance difference assumption a marginal generating unit should experience additional revenues of approximately $1/kW-year. NYISO's $5 winter revenue benefit therefore reflects an expected 550 MW of excess winter capacity in the NYCA ICAP market going forward. NYISO stated that a $5 winter revenue benefit was "a reasonable value for an additional revenue offset component."[34]

56. Mirant stated that NYISO mistakenly focused solely on capacity imports from Hydro Quebec in determining the need for, and level of, a winter revenue benefit. According to Mirant, NYISO's main reason for the winter revenue benefit is that Hydro Quebec is a winter peaking control area and does not export any significant capacity in the winter. However, Mirant asserted that the difference in Hydro Quebec's exports between the winter and the summer can be explained better by examining the export trends of PJM, ISO-NE, and Hydro Quebec together.

57. According to Mirant, PJM and ISO-NE are consistently fully subscribed in both the summer and the winter in the NYCA capacity market. Mirant pointed out, however, that while PJM and ISO-NE utilized the full capacity transfer capability into the NYISO control area that was available in 2003/ 2004, there was a temporary constraint in place for ISO-NE that prevented ISO-NE from exporting an additional 350 MW.[35] The result

[34] *See* NYISO's Clarification of Proposed ICAP Demand Curves, September 22, 2004, at 4.

[35] The constraint was temporarily in place due to a transmission outage in the ISO-NE control area that was expected to impact ISO-NE's system for the entire winter. The constraint reduced the export capability from 950 MW to 600 MW. *See* IPPNY's Protest in Docket No. ER05-428-000, Younger Affidavit at P 25.

of this, according to Mirant, was that 350 MW of the 800 MW of available import capacity in the winter of 2003/2004 would never have been available if ISO-NE had not been constrained.

58. That temporary constraint has since been lifted, and PJM and ISO-NE again utilized their full capacity transfer capability in 2004/2005. Mirant noted that this results in only 450 MW (*i.e.*, 800 MW less 350 MW) of transfer capacity available to Hydro Quebec for imports into NYISO. Mirant concludes that this means that only a 450 MW difference between winter and summer imports is possible. Mirant therefore asserts that NYISO was erroneous in setting a winter revenue benefit based on 550 MW of unused capacity when only 450 MW of unused capacity was available.

59. Mirant also asserts that NYISO's position that Hydro Quebec does not participate in the NYISO capacity market as aggressively in the winter as it does in the summer, is unfounded. According to Mirant, Hydro Quebec consistently uses its full transfer capability in March and April. Mirant asserts that this maximum participation in March and April will continue for Hydro Quebec, and that as the NYISO market approaches equilibrium in the coming years, Hydro Quebec will increase its participation in the NYISO capacity market in the other winter months as well.

60. Along the same lines, IPPNY argues that recent capacity clearing prices have been well below the equilibrium price, creating a disincentive for external suppliers to provide capacity to the NYISO control area. Still, IPPNY pointed out, Hydro Quebec and others have combined to reduce unused capacity to just 350 MW, 200 MW below the figure on which the NYISO's winter revenue benefit is based. IPPNY argues that, as NYISO capacity prices rise to equilibrium levels, participation in the NYISO capacity market will strengthen significantly, reducing that 350 MW of unused capacity even further.

61. IPPNY raises a different objection to the NYISO's winter revenue benefit. IPPNY notes that the 1,400 MW difference in available capacity between the summer and winter capability periods is based on generation that was online as of January 1, 2004. According to IPPNY, over 2,800 MW of combined cycle units are either under construction or have been completed, and are either set to come online in 2005 or have already come online. IPPNY states that this additional generation will result in an additional 300 MW difference between winter and summer capacity available. Therefore, IPPNY argues that NYISO should have used a number of 1,700 MW to represent the greater potential supply in the winter compared to the potential supply in the summer.

62. The City of New York asserts that the same winter revenue benefit that was provided to the NYCA should have also been applied to Zone J, or New York City. According to the City of New York, the Gold Book shows a winter to summer ratio of 1.063, representing 560 MW of winter excess capacity. However, the City of New York claimed that the ratio of capacity cleared in the NYISO winter 2003/2004 auction to that

of capacity cleared in the NYISO summer 2004 auction is only 1.029, representing just 175 MW of winter excess capacity. The City of New York therefore proposed that NYISO's calculated ratio of 1.063 be reduced to a more appropriate 1.03, and that the same $5 winter revenue benefit that is applied to NYCA be applied to New York City.

Commission Conclusion

63. We will accept NYISO's proposed adjustment for a winter revenue benefit for NYCA, but will require NYISO to reduce the winter revenue benefit from $5 to $4. Additionally, we will deny the City of New York's request for application of the $5 winter revenue benefit to Zone J.

64. The Commission notes that the NYCA ICAP market has experienced a surplus of capacity, resulting in low capacity prices. The current ICAP prices in NYCA are well below the equilibrium conditions on which the Demand Curves we are accepting here are based. Therefore, as NYCA capacity prices rise to equilibrium levels, it is reasonable to expect PJM and ISO-NE to continue to be fully subscribed in the NYCA capacity market. NYISO concurred with this point when it was raised at the March 21 Technical Conference.[36]

65. Based on 2004 available import capability, PJM and ISO-NE's continued full participation in the NYCA ICAP market will result in only 450 MW of available import capacity for Hydro Quebec in the winter capability periods. It is reasonable, therefore, to project a maximum decrease in winter capacity of 450 MW, assuming no winter capability period participation by Hydro Quebec.

66. Mirant pointed out that Hydro Quebec exported over 1,400 MW of capacity in March and April of 2003/2004. However, in the other four months of the winter capability period of 2003/2004, Hydro Quebec did not export any capacity into the NYISO market.[37] The reason for this is that Hydro Quebec is a winter-peaking system that does not have the excess capacity to export in the winter months. Mirant stated that Hydro Quebec only begins to have the excess capacity available to sell into the NYISO market as the temperature rises in March, April, and into the summer.

67. Hydro Quebec's participation in the winter capability period – which ranges from 0 MW in a four month period in the winter 2003/2004 to slightly higher participation in 2004/2005 – has been far too inconsistent for us to base our decision on it regarding the sustainability of NYCA's external ICAP sources. Therefore, we believe that a 450 MW decrease in winter capacity assumption is reasonable.

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[36] *See* John Charlton's Comments at the March 21Technical Conference, tr. at 194.

[37] *See* Mirant's Affidavit, Table 4.

68. Additionally, the Commission notes that the 300 MW difference between NYISO's Gold Book calculations and IPPNY's interpretation has already been accounted for by NYISO. NYISO has considered the additional 300 MW of winter capacity in obtaining the $5 winter revenue benefit.[38] According to NYISO, a 1,400 MW excess imputed in the Demand Curve and the actual excess experienced in the market would result in an $8 winter revenue benefit. However, NYISO realized that generation resources being added within the NYCA would increase the internal higher winter capacity from 1,400 MW to 1,700 MW and result in lower winter revenues of approximately $3.[39] The Commission finds that this adjustment is reasonable and appropriate, and that it sufficiently answers the concerns of IPPNY and Mirant.

69. We therefore find that NYISO incorrectly assumed 550 MW of excess winter capacity in setting the winter revenue benefit, a full 100 MW too high. Accordingly, applying the appropriate amount for the excess winter capacity figure, 450 MW, to NYISO's undisputed equation for calculating the winter revenue benefit,[40] it is appropriate to reduce the winter revenue benefit by $1. The Commission therefore finds that the resulting winter revenue benefit is $4. NYISO is hereby directed to adjust its NYCA Demand Curve accordingly.

70. The Commission will deny the City of New York's request to obtain the same winter revenue benefit for Zone J as for NYCA. In the March 21 Technical Conference, NYISO pointed out that the City of New York's calculation of the winter-summer ratio was flawed. NYISO noted that the City of New York had failed to include bilateral transactions for capacity in Zone J, meaning that the only capacity that was considered in the City of New York's calculation was capacity that was sold at auction. The City of New York did not refute NYISO on this point.

71. We agree with NYISO that the City of New York's exclusion of bilateral transactions for capacity was inappropriate. NYISO appropriately based the Demand Curve for Zone J strictly on the total capacity located within Zone J, and historical data shows that the actual committed capacity in the capacity market tracks the Gold Book ratio. Therefore, we find NYISO's calculation of Zone J's winter-summer ratio reasonable, and we will require no winter revenue benefit to be applied to Zone J.

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[38] *See* NYISO Affidavit at P 40.

[39] *Id.*

[40] NYISO explains that for every 110 MW of actual supply participation in the ICAP markets below the 1,400 MW seasonal performance difference assumption, a marginal unit should experience additional revenues of approximately $1/kW-year.

5. LM6000 Heat Rate

72. As was stated earlier, Levitan determined that LM6000 gas turbines were the appropriate peaking technology for installation inside of New York City. To support projections of the net revenue offset, one factor that must be considered is the heat rate of the peaking unit. The higher the heat rate, the higher the cost of generation and the lower the expected revenues. This is because the peaker would not be called in merit order as frequently as its bid (which should at least reflect its operating costs) would be higher. Levitan assumed a net heat rate of 9,739 Btu/kWh for LM6000 gas turbines in the New York City region.

73. Several protesters argue that this heat rate is too low and does not reflect recent operating experience. Keyspan and NRG recommend that a heat rate of 10,400 Btu/kWh be used instead, based on an analysis of available heat rate data from 2003 for the NYPA LM6000 units conducted by PA Consulting. Through modeling, PA Consulting determined that the effect of using this alternative heat rate instead of the Levitan value would be a reduction of 15-20 percent in estimated net energy revenues.

74. Seth Parker of Levitan responded to Keyspan's protest by noting that the higher actual heat rate experience of the NYPA LM6000 units may be due to a variety of factors. First, Levitan suggests that station loads imposed by inlet air chillers will increase fuel consumption and therefore heat rates. Second, Levitan responds that the NYPA LM6000 units were operated at less than full capacity in order to not invoke Article X siting review regulations, *i.e.*, in their installed dual unit configuration, the NYPA units were limited to 79.9 MW, about 20 percent lower than their rated output at 59 degrees F ISO conditions. According to Levitan, when a plant is operated, the "further and further away from full load output, [its] heat rate gets worse and worse."[41] Third, the historical data do not provide any information on the number of hours that the units operated at full or part load. Fourth, Levitan questions the basis for PA Consulting's estimate for startup costs, *i.e.*, fuel used for start-up of the peakers. Levitan notes that higher startup costs will increase heat rates. Levitan argues that PA Consulting does not have any basis for using 3 percent of total fuel, and the actual number could be higher. Keyspan's response to Levitan's arguments about part-load operation is that the restriction of output on the NYPA units is not significant, particularly in the summer, and should not account for the significant difference in heat rates.

Commission Conclusion

75. The Commission finds that NYISO's assumed heat rate for LM6000 units within New York City is reasonable for the reasons stated by Mr. Parker of Levitan about the difficulties of applying NYPA experience to new turbines. While Keyspan provides data showing that actual experience with LM6000 units has produced higher heat rates than the Levitan assumption, its data are incomplete. We find that the points about Keyspan's

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[41] Comments of Seth Parker, Levitan, March 21 Technical Conference, tr. at 76, lines 9-10.

analysis raised by Levitan during the technical conference (*e.g.*, that the NYPA units are operated at less than full load, and that start up costs may be different than PA Consulting's 3 percent assumption) cast sufficient doubt on their validity that the Commission cannot rely on the use of its data as a basis to find Levitan's heat rate unreasonable.

6. Ancillary Service Revenues

76. NYISO's proposed net revenue offset includes revenue from the provision of ancillary services. For the Rest-of -State Region (NYCA), NYISO includes ancillary service revenues from participation in the 30-minute reserve market, based on the ability of the 7FA peakers to provide such services. For New York City and Long Island, NYISO proposes to include, in addition to those for the NYCA units, revenues from the 10-minute spinning reserve market. Keyspan asserts that ancillary service revenues from 10-minute reserves should not be included in the net revenue estimate for the New York City region because the peakers selected by NYISO cannot provide 10-minute reserves.[42] Keyspan asserts that the ICAP Working Group concluded that the LM6000 peaking units assumed to be built in New York City and Long Island cannot provide 10-minute reserves because they are equipped with high temperature selective catalytic reduction units. Selective catalytic reduction units require at least 20 minutes to reach their operating temperatures. Consequently, they will not be able to quickly respond to provide 10-minute reserves.

77. Keyspan estimates that removing ancillary service revenues from NYISO's proposal would reduce the net revenue offset for the New York City and Long Island regions by $2 per kW-year.[43] Seth Parker of Levitan defended the inclusion of ancillary service revenues in the offset. Mr. Parker stated that the LM6000 aeroderivative gas turbines are capable of achieving the 10-minute-reserve requirement of achieving full load operation in ten minutes. He stated that while units built by the New York Power Authority within New York City were not designed to and do not provide ten minute non-spinning reserves, other aeroderivative units do provide 10-minute reserves. In addition, he stated that there is some flexibility, and that environmental regulators "would perhaps be willing to consider allowing those kinds of permit conditions for the sake of starting reliability."[44] He also stated that the 7FA turbine is capable of achieving full load

[42] *See* statement of Madison Milhous at March 21 Technical Conference, tr. at 131.

[43] Keyspan Comments at 17.

[44] Comments of Seth Parker, Levitan, March 21 Technical Conference, at 70, lines 17-19.

operation in thirty minutes, given sufficient notification and preparation. Con Ed suggests that there are also additional ancillary service revenue sources, such as voltage support, that all turbine could receive that have not been considered by NYISO.

Commission Conclusion

78. The Commission finds that NYISO's assumptions about net revenues from ancillary services for the NYCA region are reasonable, but finds that the assumed net revenues from ancillary services for the New York City and Long Island regions are not reasonable. Levitan appropriately modeled the limited ability of 7FA gas turbines to participate in ancillary services markets in NYCA. We find that the record indicates that the 7FA gas turbines can participate in the 30-minute reserves market, and no party protested the inclusion of these revenues. In the New York City and Long Island regions, however, the Commission finds that Keyspan's arguments about the inability of LM6000 gas turbines to participate in 10-minute reserve markets due to environmental restrictions to be compelling. Levitan and NYISO did not provide a cogent response to Keyspan's points on the required 20-minute period required to bring selective catalytic reduction units up to temperature. Levitan's argument, that these units have the operating capability to participate in these markets has not been supported, and its argument that environmental regulators may provide sufficient flexibility in the future to allow these units to operate in these markets, is speculative at best. Consequently, we adopt Keyspan's recommended adjustment of $2/kW-year, based on Levitan estimates, for the New York City and Long Island regions to reflect this change. NYISO is hereby directed to adjust its New York City and Long Island Demand Curves accordingly.

C. Zero Crossing Point

79. The Zero Crossing Point is the point on the Demand Curve that crosses the horizontal axis, that is, where the price of capacity falls to $0. NYISO's tariff specifies that the Zero Crossing Point for the upcoming year, 2005/2006, shall remain at the point that has applied since the inception of the ICAP Demand Curve, that is, 112 percent of the minimum requirement for NYCA, and 118 percent for New York City and Long Island. Neither NYISO nor any other party proposes to amend the tariff on this issue. The issue in this proceeding concerns what the Zero Crossing Point should be for the following two years, 2006/2007 and 2007/2008.

80. Once the Annual Reference Value has been established, the Zero Crossing Point determines the slope of the Demand Curve. The higher the Zero Crossing Point, the flatter the Demand Curve. Flatter curves have at least two benefits. First, they reduce price volatility, because changes in supply result in smaller changes in price. As a result, new investments are less risky, which should reduce the financing costs of new capacity. Second, flatter curves reduce the incentives of suppliers to exercise market power, because withholding supplies would result in a smaller price increase. These benefits of a flatter curve are offset, from the point of view of load serving entities (LSEs), by the fact that a higher Zero Crossing Point will increase the amount of capacity that LSEs will

be required to procure, since increasing the Zero Crossing Point shifts the Demand Curve to the right. However, whether the resulting increase in the quantity of ICAP increases LSEs' total bills depends on the effect on the ICAP price. A higher ICAP price will increase LSEs' total bills, but a sufficiently lower ICAP price could reduce LSEs' total bills. Shifting the Demand Curve to the right along the supply curve would tend to increase ICAP prices, but making the Demand Curve flatter could lower the supply curve by reducing the incentive to withhold capacity and by reducing suppliers' risk and financing costs, and these latter effects could reduce ICAP prices. It is not clear which effects predominate.

81. All parties agree that the proposed Zero Crossing Points should be adopted for the 2005/2006 period according to the tariff. Disagreements on the appropriate values for the proposed Zero Crossing Points concern the values for the 2006/2007 and 2007/2008 periods. Group I (NYISO, Levitan, IPPNY, NYPSC, and David Patton) favors maintaining the Zero Crossing Points used during the phase-in period for these two intervals while Group II (City of New York, Indicated NY Entities, and LIPA) favors reducing the values for the NYCA from 112 percent proposed by the NYISO to 109 percent. In the alternative, Group II would favor deferring the Zero Crossing Point decision for the second two periods and conducting an in-depth analysis to determine appropriate values. Alternative Zero Crossing Points for the other regions are not explicitly addressed.

82. Group I supports its 112 percent Zero Crossing Point for the NYCA by emphasizing the importance of setting the Zero Crossing Point to discourage withholding and reduce price volatility that lowers investment risk and the long-term cost of capital. An analysis by NYPSC[45] defines a Zero Crossing Point that would make withholding by the largest supplier unprofitable whenever market prices are at least two-thirds of the reference value, a situation that represents normal market conditions. The Zero Crossing Point that achieves this objective must be set at a capacity level that is at least 50 percent greater than the largest supplier's portfolio not subject to price caps. [46] Because the largest supplier in the NYCA has over 3,000 MWs of capacity not subject to price caps, capacity at the Zero Crossing Point should be approximately 4,500 MWs and this is achieved with a Zero Crossing Point equal to 112 percent. Outside of the NYCA, protection against market power is provided by price caps as well, but a smaller Zero Crossing Point than that proposed could introduce undesirable price volatility. The analysis points out, for example, that entry of a 500 MW plant in New York City could result in as much as a 30 percent reduction in capacity prices under its proposed Zero Crossing Point. A smaller Zero Crossing Point would make the curve even steeper and increase price volatility even more.

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[45] Appendix A of Affidavit of Thomas Paynter, NYPSC.

[46] Comments of Thomas Paynter, NYPSC, March 21 Technical Conference, tr. at 235, lines 15-20.

83. Group II parties recommend a Zero Crossing Point of 109 percent for the Rest-of-State Demand Curve, on the grounds that end-use consumer costs would be minimized at that level. They offer an analysis by Navigant Consulting, Inc.[47] to support their view that the Zero Crossing Point should be 109 percent for NYCA instead of the 112 percent proposed by NYISO. The analysis compared three linear demand curves for the NYCA, each defined by the same reference point and one of three Zero Crossing Points, 112 percent as proposed by NYISO, and two smaller values -- 110 percent and 108 percent. The analysis calculated the annual cost of ICAP under each demand curve assuming the largest supplier maximizes its profits by withholding. When the largest supplier has a 2,000 MW portfolio and the market is in an overall surplus, the analysis shows lower annual ICAP costs if the demand curve is defined by a 108 percent or 110 percent Zero Crossing Point instead of the 112 percent Zero Crossing Point. When the largest supplier has a 3,000 MW portfolio, the results are different, with each demand curve producing the least cost outcome for different levels of surplus. For a typical LSE in this case, the analysis concludes that a 108 percent Zero Crossing Point increases total ICAP costs relative to the 110 percent and 112 percent Zero Crossing Points while total costs are approximately the same under the 110 percent and 112 percent Zero Crossing Points. Although this analysis shows the value of a flatter demand curve and larger Zero Crossing Point for mitigating withholding incentives, Group II emphasizes that withholding is not a major concern since it asserts most LSEs are hedged. Consequently, it recommends a 109 percent Zero Crossing Point for the NYCA.

Commission Conclusion

84. We agree with the Group I parties that the proposed Zero Crossing Points are reasonable. We agree that the associated flatter Demand Curve will result in lower incentives to exercise market power, as well as lower price volatility that will tend to lower risk and investment financing costs. We disagree with the parties in Group II that the study by Navigant supports a lower Zero Crossing Point; indeed, we find that the study supports NYISO’s proposal. While the study showed that a typical LSE’s total costs would be minimized with a Zero Crossing Point of 109 percent when the largest supplier’s capacity is 2,000 MW, the largest supplier in the Rest-of-State market has a capacity of over 3,000 MW. The Navigant study concludes that when the largest supplier’s capacity is 3,000 MW, an LSE’s total costs would not be reduced by lowering the Zero Crossing Point below the 112 percent level proposed by NYISO; indeed, lowering the Zero Crossing Point to 108 percent would increase an LSE’s total costs. Thus, for all of these reasons, we accept NYISO’s proposed Zero Crossing Points for the three-year period.

[47] “Description of Analysis of Potential Zero-Crossing Points,” by Kevin B. Jones, Ph.D., Navigant Consulting, March 21, 2005.

D. Guidance on Future Demand Curve Reset Filings

85. To avoid any similar delays in the review of future filings, we suggest that in future filings NYISO lay out exactly what considerations led it to reach its conclusion regarding each issue, along with supporting documents backing up each conclusion. This would be much more helpful than a flat conclusory statement that each conclusion was reached based on NYISO's best judgment and was fully debated in the stakeholder process. The Commission must rely on evidence in the record to approve the applicant's proposals and may not merely rubber stamp NYISO's findings.

86. Furthermore, given the importance to all the parties of deciding these issues promptly, we direct NYISO to make future such filings well in advance of the requested action date, rather than seeking filing waivers. In addition, the Commission is concerned that the controversy associated with this proceeding suggests that the three-year reset process implemented by the NYISO is not sufficiently transparent and workable. Consequently, we direct NYISO, after stakeholder review, to file revisions to its Services Tariff within 180 days of the date of issuance of this order to implement changes to the procedures for setting and reviewing the parameters of the ICAP Demand Curves to ensure that future reset processes are more efficient and transparent.

87. Finally, we encourage NYISO and its stakeholders to continue their evaluation of Zero Crossing Points for the next three-year review. The Zero Crossing Points and the resulting slope of the Demand Curves have effects on investment financing costs and reliability, as well as on the incentives to exercise market power. We urge NYISO and its stakeholders to include estimates of these effects in the next three-year review and the associated proposals for Zero Crossing Points.

The Commission orders:

(A) NYISO's proposed revisions to its Services Tariff, as modified, are hereby accepted for filing, and the previously established refund condition is hereby removed, as discussed in the body of this order.

(B) NYISO is hereby directed to make a compliance filing, showing its Services Tariff as directed to be modified in the body of this order, within 30 days of the date of issuance of this order.

(C) NYISO's motion for expedited action and alternative request for rehearing are hereby dismissed as moot, as discussed in the body of this order.

(D) NYISO is hereby directed to file revisions to its Services Tariff within 180 days of the date of issuance of this order to implement changes to the procedures for setting and reviewing the parameters to ensure that future reset processes are efficient and transparent, as discussed in the body of this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.