UNITED STATES OF AMERICA 86 ferc ¶ 61, 062
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

Central Hudson Gas & Electric Corporation	)	
Consolidated Edison Company of New York, Inc.	)	Docket Nos. ER97-1523-000, OA97-470-000 and ER97-4234-000
Long Island Lighting Company	)	
New York State Electric & Gas Corporation	)	
Niagara Mohawk Power Corporation	)	
Orange and Rockland Utilities, Inc.	)	
Rochester Gas and Electric Corporation	)	
and	)	
New York Power Pool	)	

ORDER CONDITIONALLY ACCEPTING TARIFF AND
MARKET RULES, APPROVING MARKET-BASED RATES,
AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued January 27, 1999)

In this order, the Commission addresses certain aspects of the Independent System Operator (ISO) proposal submitted by the Member Systems 1/ of the New York Power Pool (NYPP)(collectively, Member Systems or Transmission Providers) to comprehensively restructure the wholesale electric market in New York. This order conditionally accepts, with modifications, the proposed New York ISO Tariff (ISO Tariff) and the proposed market rules of the

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1/ The seven public utility Member Systems are Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (ConEd), Long Island Lighting Company (LILCO), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation (Niagara Mohawk), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (Rochester G&E). The eighth Member System, the New York Power Authority, is not a public utility. For the ease of reading, rather than distinguishing repeatedly between the two, we shall refer to all eight together as Member Systems or Transmission Providers.

ISO. The order also grants the Member Systems' request for market-based rates. In addition, we will set for hearing certain aspects of the proposed rates and provide for settlement judge proceedings, as discussed further, below.

I. Background

On January 31, 1997, the Member Systems filed with the Commission a conditional proposal to establish an ISO and related entities in order to form a fully competitive wholesale electricity market in New York. The filing included the following documents: (1) ISO Agreement; (2) New York Power Exchange (NYPE) Agreement; (3) NYPE Tariff; 2/ (4) New York State Reliability Council (NYSRC) Agreement; (5) ISO-NYSRC Agreement; (6) ISO-Transmission Provider Agreement; and (7) ISO Tariff. 3/ The Member Systems submitted a filing on May 2, 1997, to supplement information concerning the NYSRC included in its January 31 Filing.

On December 19, 1997, the Member Systems submitted an additional supplemental filing (December 19 Filing). The Member Systems explain that the changes included in this supplemental filing were motivated by extensive discussions with the New York Public Service Commission (New York Commission) and various market participants, as well as recent Commission guidance regarding implementation of ISO principles and transmission pricing policies.

2/ The Member Systems have not requested acceptance of the NYPE Tariff or the NYPE-ISO Agreement at this time. According to the Member Systems, they are contemplating alternative approaches for the establishment and operation of the NYPE. In addition, they state that the NYPE need not be in place since (1) market participants need not go through a power exchange to access the ISO for market transactions, and (2) the New York ISO already has the responsibility for conducting security constrained unit commitment and dispatch functions. Therefore, this order does not address the NYPE further.

3/ This order requires certain modifications to the proposed ISO Tariff, which must be filed within 90 days of the date of this order. To the extent these tariff modifications necessitate corresponding changes to any of the agreements noted in the text above, they should also be filed in the compliance filing.

The Member Systems' proposal includes several key operational features, which will be addressed in greater detail below, including: (1) the establishment of an hourly spot energy market under a two-settlement system; (2) the implementation of congestion pricing for transmission services, both of which are centered around the concept of locational based marginal pricing (LBMP); (3) the creation of a new financial instrument -- transmission congestion contracts (TCCs); and (4) markets for certain ancillary services. Upon Commission approval, the New York ISO will facilitate the implementation of these operational features. 4/

On June 30, 1998, the Commission issued an order conditionally authorizing the establishment of the New York ISO. Central Hudson Gas & Electric Co. et al., 83 FERC 61,352 (1998), reh'g pending (June 30 order). The order made an interim finding that the proposal, with certain modifications, satisfied the Commission's 11 ISO Principles as outlined in Order No. 888. 5/ However, the order deferred consideration of the tariff issues,

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4/ The Member Systems have not yet submitted a section 203 filing requesting a transfer of control of all necessary facilities to the New York ISO. 16 U.S.C. § 824b (1994). We note that the New York ISO may not begin operations until such a filing is submitted and approved by the Commission.

5/ See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540, FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

The June 30 order also conditionally approved certain proposed ISO procedures, such as the ISO Board and committee governance structure. However, the order directed the parties to negotiate and propose a revised committee voting structure. In addition, the order deferred acceptance of the agreements filed by the Member Systems. Rehearing of the June 30 order is pending and will be addressed in a future order.

market rules and request for market-based rates. 6/ These matters are the subject of this order.

II. Notice of Filings and Interventions

Docket Nos. ER97-1523-000 and OA97-470

In the June 30 order, we described the Member Systems' filings in Docket Nos. ER97-1523-000 and OA97-470-000. We permitted various parties to intervene and accepted answers to requires for relief and protests. In addition, we deferred various requests for hearing and technical conferences that concerned pricing and rate issues. Here, we consider the arguments raised by intervenors in these dockets insofar as they relate to the Member Systems' tariff and market rules.

In addition, since we issued the June 30 order, AES NY, L.L.C. (AES NY) filed a motion to intervene out-of-time in Docket No. OA97-470-000 and Southern Energy Bowline, et al. (Bowline) and Energy Marketers Coalition filed a motion for leave to intervene out-of-time in both dockets.

Docket No. ER97-4234-000

Notice of the Member Systems' filing in Docket No. ER97-4234-000 was published in the Federal Register, 62 Fed. Reg. 48,080 (1997), and 63 Fed. Reg. 69 (1998), with protests and motions to intervene due on or before January 23, 1998. Motions to intervene and protests, and notices of intervention were filed by the parties listed in Appendix A. The Member Systems filed an answer to various intervenor protests.

III. Discussion

A. Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1998), the notices of intervention and the timely, unopposed motions to intervene serve to make the intervenors listed in Appendix A parties to this proceeding. In addition, given the stage of this proceeding, and the absence of undue delay or prejudice, we find good cause to grant the untimely, unopposed motions to intervene of AES NY, Bowline and Energy Marketers Coalition in Docket Nos. ER97-1523-

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6/ The request for market-based rate authorization was separately docketed as ER97-4234-000.

000 and OA97-470-000. In addition, given the stage of this proceeding, and the absence of undue delay or prejudice, we find good cause to grant the untimely, unopposed motions to intervene of the parties listed in Appendix A in Docket No. ER97-4234-000.

Although the Commission's Rules of Practice and Procedure do not permit answers to protests, 7/ given the complex nature of this proceeding, and given that the answer helps in clarifying certain issues, we will accept the answer filed by the Member Systems.

B. New York ISO Tariff

1. Proposed Transmission Service

Description

Member Systems have not adopted the Commission's *pro forma* tariff and, in fact, have not proposed to offer transmission service under a separate tariff. Instead, the New York ISO Tariff combines transmission service under non-*pro forma* terms and conditions, the operation of an hourly spot market, and the administration of certain aspects of the NYRSC that deal with generation reliability. 8/

The proposed ISO tariff does not define transmission service in terms of point-to-point or network services, as does the *pro forma* tariff. The tariff covers transmission service to entities purchasing from the hourly spot market or requesting stand alone transmission service for bilateral transactions. The tariff accommodates transmission services to meet loads within the New York Control Area (NYCA) as well as exports and through transactions.

There is no notion of firm service at a fixed price under the tariff and the Member Systems contend that firm service can be approximated through the acquisition of Transmission Congestion Contracts (TCC), financial instruments that protect

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7/ *See* 18 C.F.R. § 385.213(a)(2) (1997).

8/ As initially proposed, the NYPE was to be a separate entity. The Member Systems now propose that the ISO perform power exchange operations.

the holder from congestion costs when the system is constrained. However, as discussed later in this order, TCCs are renewed every six months. Accordingly, to the extent acquisition of a TCC is an adequate proxy for firm transmission service, customers compete for firm service anew every six months. 9/

Customers purchasing through the spot market will have no transmission service scheduling requirements; they will simply direct the ISO to deliver energy from the spot market. Customers that want to engage in bilateral power sales, including customers that are grandfathered under existing contracts, must schedule their transactions a day ahead. Other than grandfathered firm commitments (discussed more extensively later in this order), bilateral transactions will be designated as firm only if the customer is willing to pay congestion charges. 10/ Otherwise, they will be designated as nonfirm. The ISO will schedule nonfirm transaction requests only if its day ahead projections indicate that there are no constraints. Schedules may be changed up to 90 minutes before the hour.

The proposed ISO tariff adopts the pro forma tariff definition of eligible customer in all but one respect. The difference involves access for retail transmission services under a state retail access program. The pro forma tariff provides for retail transmission service provided pursuant to a state requirement that the transmission provider offer unbundled retail transmission service, while the proposed tariff provides for retail transmission service to any entity taking unbundled transmission service pursuant to a "voluntary" state retail access program.

The New York ISO Tariff provides that only direct customers may interact directly with the ISO. Direct customers are defined as entities that are qualified to submit schedules to the ISO and

9/ Member Systems hold out the possibility that TCCs may be offered for longer terms at some point in the future, but they make clear that under no circumstances may the term extend beyond the end of a transition period when full retail access occurs, i.e., the point at which Member Systems will be placing themselves fully under the tariff.

10/ Congestion charges are discussed later in this order. Member Systems' congestion proposal is modeled in large part on the locational marginal pricing (LMP) method that the Commission approved in PJM. See Pennsylvania-New Jersey-Maryland Interconnection, et al., 81 FERC ¶ 61,257 at 62,253-54 (1997), reh'g pending (PJM).

to participate in the ISO settlement process on their own behalf or on behalf of others. To qualify as a direct customer, the entity must satisfy certain criteria, including creditworthiness standards and specifications for communication.

The proposed New York ISO tariff includes a reciprocity provision which does not reflect the pro forma tariff language. While most of the deviations from the pro forma tariff language appear to be editorial rather than substantive, one sentence appears to expand the reciprocity requirement. 11/

The New York ISO tariff also includes liability and indemnification provisions which, as discussed later, differ from the pro forma tariff.

While the proposed tariff addresses transmission expansion at several points, the procedures for expansion are confusing. The tariff provides that the New York ISO will perform a system study if it receives a request from a party proposing a new generator or interconnection with the New York transmission system study. The tariff also states that a direct customer may request a facilities study which the ISO shall pass on to the affected Transmission Provider. While the ISO will review the results of any facilities study performed by a Transmission Provider to consider impacts on reliability, the ISO shall have no authority to require a Transmission Provider to construct a network upgrade. 12/

11/ It states:

> A Direct Customer that is a member of a power pool or regional transmission group ("RTG") or ISO also agrees to provide service comparable to the transmission service provided under the power pool or RTG ISO [sic] agreement or tariff over the systems of the members of such power pool or RTG or ISO on similar terms and conditions over facilities: (i) used for the transmission of Energy in interstate commerce owned, controlled or operated by the Direct Customer or its corporate affiliate; and (ii) used for the transmission of electric Energy in interstate commerce owned, controlled or operated by the Direct Customer's corporate affiliates. ISO Tariff, Sheet Nos. 45-46, Part 7.1.B.

12/ Currently, the only Transmission Providers are the Member

(continued...)

Protests and Commission Response

Absence of point-to-point and network services

Municipal Electric Utility Association of New York (MEUA) complains that the proposed tariff is unacceptable because it fails to offer network and long-term firm point-to-point services as required under Order No. 888. MEUA complains that the only services offered under the New York ISO tariff are non-firm, bundled energy/transmission arrangements. MEUA states that, while these tariff terms may serve the interests of the Member Systems whose resources are located within their own service areas, transmission dependent utilities such as MEUA require long-term firm transmission service if they are to reach off-system resources as a competitive alternative to the Member Systems. MEUA contends that effective competition will be impeded if entities do not have the ability to enter into power supply contracts and obtain long-term firm transmission service commitments. Independent Power Producers of New York (IPPNY) also expresses concern about obtaining long-term commitments.

Member Systems respond that their proposal is "functionally equivalent or superior to" the transmission services required under the pro forma tariff. In support, they explain that all requestors are assured transmission service in the absence of congestion while, in the presence of congestion, TCCs, like firm transmission rights under the pro forma tariff, may be purchased ahead of the day of dispatch.

Member Systems have not demonstrated that their proposed tariff is in all respects consistent with or superior to the pro forma tariff terms and conditions. Most significantly, it fails to offer the long-term firm transmission services that are required under the pro forma tariff. We disagree that the availability of TCCs will approximate the long-term firm transmission services that are offered under the pro forma tariff to allow transmission customers to make power supply arrangements that rely upon long-term firm transmission commitments because

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12/ (...continued)
Systems, i.e., the investor-owned utilities and New York Power Authority that comprised the New York Power Pool. Under the proposed restructuring, other entities may seek designation as a Transmission Provider if they own at least 100 circuit miles of transmission with a voltage of 115 kV or higher.

TCCs would have a term of only six months. 13/ While we have approved a similar proposal for the California ISO, we did so in conjunction with a state-wide retail access program which required all public utility transmission providers to place themselves under the same terms and conditions. In addition, while we approved that aspect of the California ISO tariff that fails to offer a mechanism to obtain long-term firm transmission commitments, we did so only on a temporary basis.

Unlike California, there is no state-wide retail access program and Member Systems will not be placing their bundled retail power sales under the tariff's terms. With respect to absence of long-term firm transmission service at a fixed price under the New York ISO tariff, for example, this proposal allows Member Systems to retain their long-term firm rights, while providing no avenue for customers under the proposed New York ISO tariff to obtain long-term firm rights. Accordingly, we direct the Member Systems to reinstate the pro forma long-term firm tariff services and to extend to all users enough six-month TCCs to cover the length of their transmission service. 14/ This requirement will not be incompatible with other aspects of the proposed restructuring, as evidenced by the ability of two neighboring regions -- PJM and NEPOOL -- to accomplish similar pool restructurings (e.g., containing LBMP congestion management, Fixed Transmission Rights, and ISO-operated spot markets) without eliminating the pro forma tariff services. 15/

We shall also direct Member Systems to file a transmission tariff that is separate from the rate schedules that govern non-transmission functions, e.g., its operation of a spot market and administration of the NYRSC Agreement. We recognize that there

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13/ We discuss TCCs comprehensively later in this order and conclude that TCCs significantly enhance the open access requirements of the pro forma tariff as an efficient substitute for the reassignment of physical transmission rights that entities obtain under the pro forma tariff. However, given the facts of this case, we cannot conclude that TCCs, as proposed by the Member Systems, will serve as a proxy for comparable access to tariff customers.

14/ Member Systems have accommodated their own long term uses by allocating to those uses enough six-month TCCs to cover the length of those uses.

15/ See PJM, 81 FERC at 62,267; New England Power Pool, 83 FERC ¶ 61,045 (1998) (NEPOOL I); New England Power Pool, 85 FERC ¶ 61,379 (NEPOOL II).

may be some duplication of common features, e.g., LBMP pricing is based upon the prices determined in the energy market. However, it is necessary that transmission and ancillary services be offered as a separate product that is available on a stand-alone basis. Again, Member Systems can look to neighboring systems to observe feasible methods to accomplish this separation.

Eligibility Provisions

As noted above, the proposed tariff includes a definition for eligible customer that deviates from the requirements of the pro forma tariff in that it offers unbundled retail service only on a voluntary basis, and does not offer such service if it is pursuant to a state requirement that the Member Systems offer the service. The New York Commission objects to this change. Multiple Intervenors (MI) complain that the tariff does not encompass unbundled retail transmission service. Finally, MEUA and MI complain that only direct customers, which MEUA characterizes as a euphemism for Transmission Providers, may interact directly with the New York ISO, thereby relegating other transmission users to deal through the Transmission Providers.

Member Systems respond that their revision to the pro forma tariff definition of eligible customer is necessary because the "FERC does not have legislative authority to compel retail wheeling." 16/ They contend that the proposed language is consistent with the "Commission's pronouncements of its jurisdictional limitations in Order Nos. 888, 888-A and 888-B." 17/ Member Systems assert that their proposal does not currently extend to unbundled retail transmission service and they will decide later what changes to the tariff are needed to accommodate any retail access they agree to provide. Finally, Member Systems assert, without explanation, that MEUA will qualify as a direct customer.

While we have already directed Member Systems to reinstate the pro forma tariff terms and conditions generally, we emphasize that Member Systems must reinstate the pro forma tariff definition for eligible customer in particular. As we have held repeatedly in prior cases, this aspect of the pro forma tariff is a fundamental term and condition which cannot be revised in a

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16/ Member Systems Answer at 117 (Filed March 2, 1998).

17/ Id.

superseding tariff filing. 18/ We reject Member Systems' arguments that their revision is necessary because the Commission does not have authority to compel retail wheeling and that their language is consistent with our jurisdictional pronouncements in Order Nos. 888, 888-A and 888-B. The Commission in the 888 series of orders clearly recognized that it cannot order direct retail transmission but also made a specific determination that if unbundled retail transmission is provided voluntarily or provided pursuant to a state requirements, the rates, terms and conditions of the transmission are within the Commission's exclusive jurisdiction and must, absent Commission authorization, be provided under the pro forma tariff. The eligibility provision was very carefully written with these jurisdictional determinations in mind, and Member Systems provide no basis to raise arguments seeking to re-write what was decided in the Order No. 888 series of orders.

We shall also direct Member Systems to eliminate the limitation that only direct customers may interact with the New York ISO as it relates to transmission service. While it may be acceptable to establish nondiscriminatory eligibility requirements beyond those set forth in the pro forma tariff for participation in ISO activities other than transmission service (i.e., the reserve sharing arrangements of a power pool or participation in a spot market), Member Systems have proffered no basis to impose additional requirements on wholesale transmission customers. 19/

Reciprocity

We shall direct Member Systems to reinstate the pro forma tariff reciprocity provision, modified only to provide that both the Transmission Providers and the ISO are the beneficiaries of this requirement. To the extent that the other proposed changes are intended to be editorial rather than substantive, these

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18/ See, e.g., New York State Electric & Gas Corp., 78 FERC ¶ 61,114 (1997), reh'g denied, 82 FERC ¶ 61,209 (1998).

19/ We recognize that, in many retail access programs, retail customers use intermediaries to obtain transmission service. For example, PJM uses agency agreements. Member Systems note that further modifications to the tariff will be required to accommodate retail access. The Commission will consider, on a case-by-case basis, proposed revisions to the pro forma tariff that are intended to implement retail access, but which do not affect access by wholesale customers.

revisions introduce unnecessary confusion. For example, read literally, the earlier quoted sentence (see supra, n. 10) would appear to require an entity like Portland General Electric Company to offer PJM-type transmission services over its facilities because its affiliate, Enron, is a member of the PJM pool. To the extent the proposed changes were not intended to be editorial in nature and were, instead, intended to substantively change the reciprocity requirement, Member Systems have provided no explanation or justification of the purpose of these revisions.

Expansion

A number of intervenors express concerns about how transmission expansion will be addressed. MEUA expresses concern about who will be evaluating expansion decisions and states that such decisions should be placed under the responsibility of a regional transmission group that would coordinate planning to relieve persistent or significant constraints in an economical manner.

Sithe/Independence Power Partners, L.P. (Sithe) complains that, since each Transmission Provider will be competing against other transmission users for generation sales, it is inappropriate to give them the exclusive authority to determine whether and how to relieve system constraints (as appears to be the case under Member Systems' proposal.) 20/

IPPNY complains about the lack of specificity regarding the manner in which the ISO would ultimately judge whether a proposed project meets reliability standards, whether those standards would be evaluated on a system-wide or local basis, and whether a governing body or committee would be required to approve a transmission system expansion.

Long Island Power Authority (LIPA) expresses concern that the ISO will not have adequate authority to expand the existing transmission system for reliability and economic purposes. LIPA contends that the proposal leaves expansion and the development of new transmission solely to market forces, and questions whether proper economic incentives are in place for market forces to respond. LIPA also complains that, even if market forces do respond, the Transmission Providers will have final authority to determine which transmission projects should go forward, noting

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20/ Sithe Protest at 42 (Filed March 26, 1997).

that the interests of Transmission Providers are not always aligned with other market participants. 21/

Athens Generating Company (Athens) complains that the proposed tariff fails to explain how expansion is handled with respect to interconnections with new generators. Likewise, Athens argues that the tariff fails to clarify the New York ISO's operational control over facilities constructed for a specific customer or how interconnection requests are prioritized for purposes of expansion responsibility.

The New York Commission expresses concerns about expansion planning as well.

Member Systems argue that their proposal is adequate given the movement towards a more market oriented electricity industry. They contend that market participants, based on their evaluation of congestion costs, will judge what are appropriate and effective reinforcement options and the New York Commission will have the ability to ask for illustrative reinforcement options to "help guide market participants in developing or selecting ways to reduce costs." 22/ Member Systems state that Transmission Providers will still address reliability needs within their own system. Member Systems conclude that the "command and control" and "centralized planning" approaches preferred by intervenors are inconsistent with the market-based expansion process contemplated by this proposal.

We do not disagree with the conclusion that expansion should be effected only when needed to maintain reliability or based on evidence that the market is willing to pay for expansion. However, we do not agree that this dictates the fragmented proposal put forth by Member Systems which disburses responsibilities among different parties and establishes no structured framework within which every user may pursue expansion concerns.

We also find that the expansion provisions are unclear and appear inconsistent with Order No. 888, which requires the Transmission Provider to expand the system in response to a valid request for transmission service. Indeed, Member Systems conclude that, if their customers do not benefit from an expansion, they should not be required to build it. This concept is antithetical to Order No. 888, which requires comparable

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21/ LIPA Motion to Intervene at 12 (Filed February 27, 1998).

22/ Member Systems Answer at 99 (Filed March 2, 1998).

access for all transmission users, not just the Transmission Providers. We expect that, by reinstating the pro forma tariff terms, these defects will be remedied because the pro forma tariff clearly requires the transmission provider (here, the New York ISO and the Transmission Providers) to expand the system to meet new requests for service. 23/ We recognize that the pro forma tariff filed in response to this order may be revised to delineate the division of responsibility for expansion matters or to address pricing matters related to expansion or related TCCs, but we will not entertain changes that eviscerate the pro forma tariff requirement that the system be expanded by Transmission Providers when necessary to meet requests for service and to ensure reliability. Moreover, we shall not entertain changes that fail to give the ISO the authority and ability to accomplish this planning for transmission expansion.

Liability and Indemnification

Electric Clearinghouse (Clearinghouse) objects that the indemnification and liability provisions of the ISO Tariff are contrary to the Commission's pro forma tariff. In addition, Clearinghouse argues that the provisions are contrary to the Commission's recent pronouncements on ISO liability and indemnification in the California restructuring proceeding. 24/

The proposed tariff provides that the ISO's liability to market participants under the Tariff is limited to instances where the ISO's actions constitute gross negligence or intentional misconduct. The proposed tariff also provides that market participants are required to indemnify the ISO, Transmission Providers and NYSRC from claims arising under the Tariff, except to the extent that the actions of the indemnitees constitute gross negligence or intentional misconduct.

Consistent with our approach in WEPEX, 25/ we will require that the New York ISO tariff be modified to adopt the indemnification provisions in the pro forma tariff, without modification. In addition, we direct that the Member Systems

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23/ This expansion requirement is of course subject to state and local transmission siting requirements.

24/ Electric Clearinghouse Protest at 16 (Filed February 6, 1998).

25/ Pacific Gas & Electric Co., et al., 81 FERC ¶ 61,122 at 51,519-20 (1997), order on reh'g, 82 FERC ¶ 61,223 (1998).

remove the provision limiting the liability of the ISO in order to conform the ISO tariff with the pro forma tariff.

Definition of Native Load

The New York Commission complains that Native Load is defined in terms of the transmission provider's own retail customers, rather than all customers located in the transmission provider's control area. We conclude that the ISO tariff inappropriately departs from the pro forma tariff definition 26/ and shall direct Member Systems to reinstate the pro forma tariff definition.

Notices Concerning the Disclosure of Information

The New York Commission states that the tariff provides that the ISO may disclose certain transmission information in the case of an emergency, but if it does it will notify only the Commission. The New York Commission asks that the language be modified to provide for it to be notified as well. This is a reasonable request. We shall direct that the ISO serve the New York Commission with a copy of any notice submitted to the Commission.

Interconnection Requests Not Associated with Transmission Service Requests

Athens seeks assurance that new merchant generators may seek interconnection to the grid without taking and paying for transmission service. Member Systems respond that, while not addressed in the proposed tariff, generators may interconnect with the grid without obtaining transmission service, if output would be delivered through transmission services arranged by the purchaser or through power exchange sales. 27/

26/ Pro forma tariff section 1.19 defines Native Load customers as, "The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers." Order No. 888-A, FERC Stats. & Regs. at 30,508.

27/ Member Systems Response at 5-6 (Filed April 14, 1998).

While Member Systems' response is reasonable, it is not codified in the ISO Tariff. We shall require that the revised tariff filed in response to this order include procedures for merchant generators to arrange an interconnection in circumstances where they will not be separately obtaining transmission service.

2. Proposed Transmission Rates

Description

There are three components to the transmission charge included in the New York ISO Tariff. They are as follows: (1) the Transmission Service Charge; (2) the Transmission Use Charge; and (3) the NYPA Transmission Adjustment Charge.

Transmission Service Charge

The Transmission Service Charge is an hourly rate that recovers the embedded fixed costs of the transmission system. It is assessed on the basis of hourly metered loads for deliveries within the ISO's control area (including purchases from the power exchange, bilateral transactions and imports) and on the basis of scheduled deliveries for exports and through transactions. Transactions that are not subject to this charge are the Transmission Provider's use of its own system to provide bundled retail service to its native load customers, retail transmission service pursuant to another tariff or rate schedule that explicitly provides for other transmission charges "subject to any applicable provision of the FPA," and wholesale transmission service pursuant to existing bilateral agreements (these grandfathered agreements are discussed separately later in this order).

As is the case in PJM and NEPOOL, loads within the New York ISO control area will pay a single system rate based on the costs of the transmission provider where the points of delivery are located. Export transactions and through transactions will pay a charge based on the costs of the transmission provider that owns the intertie which serves as the point of delivery to an adjacent control area. 28/ Any wholesale distribution charges associated with any of these services will be the subject of a separate charge to be filed with the Commission. Finally, Transmission Providers are authorized to offer or grant requests for discounts

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28/ This differs from PJM and NEPOOL which both use a weighted average charge of all transmission providers for these types of transactions.

with respect to Transmission Service Charges involving exports or through transactions, but all communications must be through New York's Open Access Same Time Information System (New York OASIS), and all discounts must be offered to all customers for the same period for all deliveries to the same interconnection.

The hourly rate for each transmission provider will reflect: (1) its individual transmission revenue requirement; (2) its individual scheduling, system control and dispatch costs; and (3) a transition period payment (discussed later in this order), credits reflecting revenues it receives from the sale of TCCs or related congestion revenues, revenues related to grandfathered Agreements, congestion payments received from grandfathered TCCS, and revenues related to off-system transactions. Data provided in the application indicate that the transmission revenue requirement and scheduling cost components of the formula yield charges ranging from a low of 4 mills/kWh (for Rochester G&E) to a high of 9 mills/kWh (for Con Ed). Each Transmission Provider must file its revenue requirement and scheduling charges with the Commission.

While NYPA will also be entitled to assess a Transmission Service Charge, it applies only for service to a few of NYPA's customers that are directly connected to NYPA facilities (e.g., Reynolds Metals, GM-Massena, Town of Massena and the City of Plattsburgh). NYPA's Transmission Service Charge will be, at the customer's option, either a monthly charge of $1.30/kW or an hourly charge of 3.75 mills (not to exceed $.06/kW/day or $.30/kW/week). For export transactions involving NYPA's intertie facilities, NYPA's Transmission Service Charge for transactions involving the Vermont or Ontario Hydro intertie are the hourly charges listed above. NYPA's Transmission Service Charge for transactions over the Hydro Quebec intertie are hourly charges that are about 23% higher than those quoted above. The tariff provides that NYPA will file the rates which the ISO Tariff will recover for use of NYPA's system with the Commission. The tariff also provides that NYPA's upgrades will be reflected in its Transmission Service Charge only if they do not exceed $5 million on an annual basis or they have been unanimously approved by the Transmission Providers.

Transmission Use Charge

The second rate component is the Transmission Use Charge which recovers any congestion costs associated with the transaction and marginal losses. It applies as a separate component only to bilateral transactions because the congestion cost and marginal loss component of transmission service related to the hourly spot market is recovered through the LBMP pricing used to price those transactions. 29/

NYPA Transmission Adjustment Charge

The third rate component is a NYPA Transmission Adjustment Charge which is assessed on all transactions. It is intended to recover any shortfall in NYPA's revenue requirement that is not recovered under NYPA's Transmission Service Charge. Unlike other Transmission Providers, NYPA does not operate a separate service area. Most of NYPA's customers are located in the service area of other Transmission Providers and, under the New York ISO Tariff, will pay a Transmission Service Charge based on the costs of the transmission provider where the loads are located. NYPA's transmission facilities are, nonetheless, critical elements of the New York ISO grid and a mechanism is needed to provide for NYPA to recover its costs. This surcharge spreads those costs among all customers.

Protests and Commission Response

Hearing to Consider Rate Matters

We shall establish a hearing to consider a number of rate matters. Below, we summarily rule on some issues and identify other matters reserved for hearing.

Transmission Service Charge

MEUA argues that the New York ISO should reflect a single system-wide rate based on the average costs of all Transmission Providers, rather than a single system rate based on the costs of the service area where the loads are located. We note, however, that the proposed pricing approach is one we have approved for other ISOs and we see no reason to reach a different result here. 30/

Sithe argues that the Commission should not allow the Transmission Providers to adopt the revenue requirement from their individual open access tariffs as the revenue requirement used in the rate formulas for the New York ISO Tariff. Sithe

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29/ Except for the use of marginal losses, this approach is the same approach that the Commission has approved in PJM. See 81 FERC at 62,258.

30/ See, e.g., our discussion of this pricing approach in NEPOOL I, 83 FERC at 61,233.

contends that interested parties should be allowed to pursue at hearing all cost of service issues, including the use of levelized costing methods, the inclusion of generator step-ups in the transmission revenue requirement, return on equity and the divisor used to develop the hourly charge for the New York ISO Tariff. 31/ As we did in approving similar ISO Tariffs proposed by PJM and NEPOOL, we shall accept Member Systems' proposal to adopt the present revenue requirement from their individual tariffs for purposes of designing the rates for service under the ISO tariff and shall not set these revenue requirements for hearing. However, an issue introduced for the first time in this filing is the appropriate divisor to be used to develop the hourly rate. Sithe may pursue issues concerning the appropriate divisor at the hearing ordered in this proceeding.

The New York Commission states that the formulas used (Attachment B) to compute the Transmission Service Charge are complex and therefore, a review should be conducted after 18 months' experience to consider their impact and fairness. Except for the use of Member Systems' individual tariff revenue requirement, we shall allow intervenors to pursue at hearing concerns about these formulas, including any adjustments to the individual tariff rates that have been effected in transferring those rates to the New York ISO Tariff. The New York Commission may pursue at hearing whether and to what extent the formula methodologies should be revisited in the future.

NYPA's Transmission Service Charge

Hydro Quebec (HQ) complains that NYPA proposes separate Transmission Service Charges (TSC) for each intertie, compared to the Transmission Providers who have proposed a single system rate. HQ complains that this approach is inconsistent with Commission policy and, while the Commission found that this pricing approach was satisfactory for NYPA's reciprocity tariff, the Commission should revisit this issue in the context of a pool restructuring where 35% of the transmission lines are owned by NYPA. HQ argues that this pricing method puts it at a commercial disadvantage in its commercial relations with New York utilities. HQ adds that the New York ISO tariff makes clear that the Commission will have the opportunity to review NYPA's rates for recovery under the ISO tariff. 32/

31/ Sithe Protest at 25-26 (Filed March 26, 1997).

32/ HQ Protest at 2-3 (Filed March 19, 1998).

Member Systems respond that it is not possible for NYPA to compute a TSC using the same methods as other Transmission Providers. Member Systems note that other Transmission Providers operate an integrated service area and design their TSC by dividing their revenue requirement among the total system load, but NYPA does not operate an integrated service area and has no equivalent of total system load to which it can allocate a pro rata share of its revenue requirement. 33/ Member Systems also question HQ's alleged concerns over the disparity of the rates in the two delivery points since this reflects the status quo and HQ has never before complained about the disparity in treatment. Member Systems also state that HQ ignores the fact that, under the New York ISO Tariff, rate pancaking is eliminated and transmission costs reduced accordingly.

We find that the Member Systems' proposal reasonably accommodates the unique role played by NYPA in contributing to the New York transmission grid. This proposal fosters NYPA's participation in the New York ISO by ensuring that it will recover its costs, while also allowing its customers, most of whom will be paying the Transmission Service Charge of another Transmission Provider under the New York ISO Tariff, to benefit from regional access under a single system rate. The fact that NYPA happens to control two different interties with outside control areas and will charge rates that differ by about 20% for one or the other does not lead to an unreasonable result.

Other Transmission Service Charge Issues

LIPA seeks assurance that, should it join the New York ISO, it is not relinquishing its authority to set its own rates. LIPA notes that, in approving reciprocity tariffs, the Commission has not required such relinquishment. 34/

The transmission services provided by the New York ISO are jurisdictional, notwithstanding the fact that some non-public utility entities such as LIPA may elect to join the ISO. Accordingly, even though the New York ISO transmission rates would include recovery of LIPA's costs if LIPA were to join the ISO, the New York ISO rate nevertheless would be subject to our

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33/ Member Systems explain that, if NYPA's revenue requirement were spread over its directly interconnected loads as is done by the other Transmission Providers, NYPA's TSC would be about 75 mills/kWh and would be recovered solely from the four customers with whom it is interconnected.

34/ LIPA Motion to Intervene at 11-12 (Filed February 27, 1998).

review under Sections 205 and 206. At the same time, LIPA can be assured that we are committed to fostering regional transmission arrangements that will embrace public utility and non-public utility entities alike and would not lightly take actions that might deter entities like LIPA from participating.

Transmission Use Charge

The Transmission Use Charge recovers congestion costs and marginal losses. We will discuss this issue in greater detail, below.

Congestion Charge

The congestion charge component reflects LBMP pricing modeled in large part on that we previously approved in PJM. 35/ We address the LBMP pricing fully later in this order and approve it as a general matter.

Marginal Losses

Some protestors argue that the use of marginal losses in conjunction with average cost pricing violates a long-standing Commission requirement that these charges be designed consistently. 36/ Member Systems argue that these precedents are not on point because, in prior cases, the transmission provider did not intend to apply the same rate treatment to its own native load uses as is the case here.

We disagree that this proposal violates the cited precedents, none of which involved regional transmission service under single system rates, regional treatment of losses, or regional congestion pricing under a locational-based pricing method. Under the New York ISO proposal, the variable costs of transmission (congestion and losses) will be treated consistently

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35/ 81 FERC at 62,253-54.

36/ See, e.g., Northern States Power Company, 59 FERC ¶ 61,100, reh'g denied, 60 FERC ¶ 61,076 (1992), clarification denied, 64 FERC ¶ 61,111 (1993), petition for review denied, Northern States Power Company v. FERC, 30 F.3d 177 (D.C. Cir. 1994).

under a marginal rate cost design and all fixed costs will be recovered through an access fee that eliminates rate pancaking for the use of multiple systems.

A number of parties oppose the hourly marginal loss charge because the revenues associated with hourly marginal loss charges will exceed the total hourly system loss cost. This occurs because marginal losses are computed as if every transaction were the last increment added to a fully loaded transmission system, and losses most often are higher for the last increment of load. Member Systems recognize this fact and propose to credit the overrecovery in marginal loss charges in computing the scheduling Charge. Because the scheduling Charge (discussed fully below) is designed to recover the ISO's operating costs, this proposal has the effect of reducing the ISO costs before they are allocated among transmission users on a load ratio basis. Member Systems argue that marginal losses are a critical element of their LBMP pricing because, like congestion costs, losses vary on the basis of the location of the generator and load. Member Systems contend that LBMP pricing would not provide appropriate price signals if pricing were based on average system losses.

Member Systems' express concern that the use of average costs would not accurately reflect the actual cost of losses associated with each transaction. Similarly, the fact that the total revenues from marginal losses are likely to exceed the total system loss cost indicates that Member Systems' proposal also does not accurately reflect the actual cost of losses associated with each transaction. One way to address this issue would be to queue every transaction in order to overlay them on each prior transaction request to compute the actual marginal loss associated with each. This would be infeasible given the dynamics of the integrated transmission system and certainly a matter of unending controversy. Member Systems avoid this by treating all transactions as the last increment of load, a simplifying assumption that has some merit in meeting the objective of providing price signals to market participants and promoting efficient resource use. For example, when choosing between two purchase options that have the same input cost except for losses, the buyer will select the one with the lowest marginal losses. When a purchaser makes this choice, the cost of system losses is, in fact, reduced by the marginal losses as computed by Member Systems.

The use of marginal losses is a significant component of the LBMP pricing method that we approve later in this order. Moreover, the method used to compute the marginal losses is the same method that individual utilities typically use to decide how to dispatch their resources in a manner that minimizes variable costs. Member Systems' proposal to use excess revenues to defray their operating costs, which benefits all transmission users equitably, also supports the proposed use of marginal losses; there will not be unjust enrichment as the revenues will defray costs rather than contribute to a higher return. We shall therefore accept Member Systems' marginal loss proposal with respect to tariff transmission services. Because this is an untested pricing approach, we shall require the ISO to evaluate how it works in practice and to consider, in consultation with stakeholders, whether this approach for computing marginal losses can be improved upon.

Some intervenors argue that, even if marginal losses are used to compute LBMP prices for spot market transactions, they should not be assessed for bilateral transmission services. Member Systems point out that, if a different loss scheme is used for spot market and bilateral transactions, it will create a bias between them, i.e., self-scheduled transactions will be preferred when average losses are lower than marginal losses and spot market transactions will be preferred when marginal losses are lower than average losses. We agree that losses for all transmission services, whether accomplished through a spot market transaction or a self-scheduled bilateral transaction, must be consistent.

Sithe complains that the method used to compute marginal losses is not clear and it will be unable to evaluate the marginal losses in advance. Member Systems respond that they will work with Sithe and other transmission customers to provide the information that they need. We shall allow Sithe to pursue at hearing issues concerning clarity as to the methodology used to compute marginal losses and the information made available to customers to allow informed decision making. However, as noted above, we shall accept Member Systems's proposal to adopt marginal losses for the New York ISO Tariff.

Stranded Cost Charge

The tariff includes a Stranded Investment Recovery Charge which passes through any wholesale stranded costs that the Commission has approved for recovery through the transmission rates of any transmission provider.

LIPA seeks assurance that the provisions related to stranded costs do not limit its ability to recover retail stranded costs.

37/ Sithe seeks assurance that transmission customers that are not former wholesale customers or retail-turned-wholesale customers will not be charged for stranded costs. The New York Commission objects to any treatment of retail stranded costs that circumvents its authority and argues that the tariff language be limited to wholesale stranded costs. Member Systems note that the ISO will recover stranded costs only pursuant to a Commission order and, therefore, there can be no concern that stranded cost recovery will be inconsistent with the Commission's requirements. Given that the Member Systems are required under the ISO tariff to seek Commission approval of any proposed stranded costs, intervenors' concerns can be addressed at that time.

Ancillary Services and Other Charges

The New York ISO Tariff also includes six charges that are described as Ancillary Services Charges.

The scheduling, system control and dispatch service charge recovers not just those costs related to scheduling, system control and dispatch, but all operational costs, e.g., those associated with operating the hourly spot market, market power monitoring, dispute resolution, and administering the generation reliability requirements of the NYRSC. 38/ In addition, this charge recovers any costs the New York ISO incurs as a result of inadvertent interchange or emergency transactions with other control areas, start up and minimum run charges paid to generators, the difference between the revenues associated with marginal loss charges and actual system losses, as well as the lack of precision in some of the billing parameters. 39/ Also, all of the New York ISO's start up costs will be recovered through this charge, amortized over a ten year period. The charge is assessed for all transactions, including exports and through transactions.

37/ LIPA Motion to Intervene at 9-10 (Filed February 27, 1998).

38/ As noted above, scheduling, system control and dispatch costs incurred by the Transmission Providers are recovered through their transmission service charge.

39/ For example, load serving entities will be billed based on estimated distribution of loads among buses in each local service area. If the actual distribution of load differs from this assumed distribution, the total amount collected from load serving entities could be higher or lower than the amount that should have been collected.

The voltage support (reactive supply) charge is assessed for all transactions, including exports and through transactions. The charge is based on the ISO's projected annual costs to obtain these services from suppliers of reactive power. 40/ The regulation charge is assessed for all transactions involving loads within the New York ISO control area which are served from generators also located within the control area. The operating reserve charges apply to all transactions except through transactions (i.e., including exports). These services are obtained through the ISO; however, customers may self-supply regulation service and operating reserve services. Energy imbalances are treated as a purchase from or sale to the hourly spot market.

There is also a charge for black start capability which will recover the costs the New York ISO incurs under separate contracts with Black Start providers. All loads within the New York ISO will share in these costs on the basis of a load ratio share.

Scheduling Charges

Some of the protests concerning scheduling charges relate to the recovery of minimum bid and start up costs that are not recovered through the spot market energy prices. These complainants argue that a different market mechanism should be used to deal with these costs so that there would be no unrecovered costs to pass through the scheduling charge. These concerns are addressed later in the order in the discussion of market design.

Some intervenors complain that the scheduling charge will recover out of merit generation costs incurred when storm watch conditions require that certain transmission facilities be unloaded as a precaution against unexpected outages during storms. They argue that these costs should be assessed against the beneficiaries of the storm watch procedures (primarily New York City and its environs). These complainants argue that a different allocation method should be used so that there would be no unrecovered costs to pass through the scheduling charge. These concerns are addressed later in the order in the discussion of market design.

40/ Payments made to ancillary service providers, which comprise the costs recovered through these charges, are discussed later in this order.

We note that, as has been the case in other proceedings, the ISO will recover its costs through the scheduling charge which is assessed to transmission customers, although some of the ISO's activities do not involve transmission service, e.g., some are associated with the spot market and others with generation reliability matters. We shall accept this aspect of the proposal at this time, but shall direct the ISO to revise its funding mechanism to allocate costs for non-transmission services to the parties that benefit from those other services.

Voltage Support Charges

Sithe complains that the Member Systems have proposed a different pricing approach for reactive supply based on whether the transaction involves deliveries to a load-serving entity (LSE) within the control area or not, i.e., pricing of reactive power associated with imports and intra-control area transactions is based on metered loads, while pricing of reactive power associated with exports is based on scheduled deliveries. 41/

We shall accept this aspect of the proposal. It is consistent with the billing determinants used for transmission service and reflects the fact that, for exports, the ISO must be prepared to provide voltage support for the entire scheduled amount.

Black Start Service

Citing American Electric Power Service Corp, 78 FERC ¶ 61,070 (1997), Sithe argues that black start costs are a generation service that not all transmission customers require. Sithe asks that the proposed tariff be revised to either eliminate this charge or make it optional. 42/

We shall accept this aspect of the proposal. As we noted in Order No. 888, where we discussed this issue as Restoration Service, there are two considerations with respect to blackstart capability. 43/ One involves the ability to restart a generator, while the other involves the transmission provider's ability to restart the system itself. Unlike the situation we addressed in Order No. 888, here, the ISO will not control generating resources itself. Therefore, it must contract for blackstart

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41/ Sithe Protest at 45-46 (Filed March 27, 1997).

42/ Id. at 50.

43/ Order No. 888, FERC Stats. & Regs. at 31,711.

capability in order to ensure reliable operation of the transmission system. Also, in Order No. 888 we were concerned that the customer be allowed to access generators besides those owned by the transmission provider that could provide this service. Here, the ISO will be choosing among all possible generators on the system to provide this service and will not be required to obtain this service from the transmission owners.

3. Grandfathered Agreements and Transition Plan

Description

Under the Proposed tariff, existing transmission agreements will be grandfathered in some respects and modified in other respects. With respect to existing transmission agreements that are associated with a specific generator or power supply contract, and transmission facilities agreements that contain provisions for transmission service, the existing customer will retain the right to transmit power according to the terms of its existing agreement, as long as scheduled in the day ahead market. In addition, the existing customer will continue to pay the transmission charges in that agreement directly to the Transmission Provider.

In some circumstances, these rates are frozen at present levels through a transition period and not subject to revision by either party until the transition period expires. Thereafter, rate changes are limited to embedded costs and may be changed only as permitted by the contract terms). 44/ Also, the existing transmission customer is not prevented from assigning its existing transmission agreement to support the transfer of a generator or rights under a power supply contract to an assignee. Finally, if an associated generator is retired or has its power supply terminated, the existing transmission arrangement will be terminated on the earlier of that date or the end of the Transition Period. However, if the transmission arrangement continues beyond the generator retirement or purchase termination, the existing customer will become liable for: (1) marginal losses under the ISO Tariff in lieu of any loss provision in the existing agreement; (2) ancillary service charges under the New York ISO tariff; and (3) congestion charges should its real time uses differ from the day ahead schedule.

Existing transmission customers also have the right to convert to tariff service. With respect to existing agreements

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44/ The transmission provider will credit these revenues to the revenue requirement used to establish its tariff charges.

between NYPA and its municipal and cooperative customers, the customers are entitled to choose whether or not to exercise this right of conversion. The consequences of this election are threefold: the customer becomes able to use the transmission system as flexibly as all other tariff customers (i.e., it is no longer tied to the points of receipt and delivery in its agreement; it pays the tariff Transmission Service Charge instead of its existing contract rate; and it is awarded TCCs based on the existing contract specifications. 45/ Elections to convert must be made 30 days before the implementation of LBMP pricing. 46/

With respect to existing transmission agreements between and among the Transmission Providers that do not fall into the categories discussed above, each of these will be terminated.

The Transmission Providers' use of the system to serve bundled retail load is also considered an existing transmission use. The New York ISO Tariff provides that these transactions

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45/ For example, if the existing contract is a five-year point-to-point service from Point A to Point B, the customer would be awarded TCCs for those points that cover the five-year period. The customer would be free to schedule energy anywhere on the New York ISO system, but the TCCs would protect it from congestion costs only with respect to schedules that involve Point A to Point B. Finally, the customer would be subject to the Transmission Service Charge instead of the existing contract rate.

46/ Attachment H to the New York ISO Tariff details the parties that are customers under existing grandfathered agreements:

Central Hudson	535 MW	(providers are Niagara Mohawk, NYPA and NYSEG)
ConEd	1240 MW	(providers are Niagara Mohawk, NYPA, NYSEG & LILCO)
LILCO	1020 MW	(providers are Niagara Mohawk, NYPA, and ConEd)
NYSEG	2100 MW	(providers are Niagara Mohawk, NYPA, ConEd & Central Hudson)
Niagara Mohawk	300 MW	(provider is NYPA)
O&R	270 MW	(providers are NYPA and Central Hudson)
Rochester G&E	375 MW	(providers are Niagara Mohawk, NYPA, NYSEG & Central Hudson)
3rd party	10000 MW	(providers include most NYPP members)

will be converted to point-to-point native load TCCs. The terms of these awards are unclear, but they seem to be tied to resources located outside of the transmission provider's service area. The Transmission Providers "may release these TCCs to native load customers that convert to retail access or may release them for sale on the open market." 47/

During a five-year transition period, Transmission Providers are subject to a schedule of fixed monthly transmission payments or receipts that are intended to neutralize certain impacts of the effect of the restructuring. For example, under the prior NYPP Agreement, three Transmission Providers received an additional portion of the economic dispatch savings, purportedly to recognize that they provided the bulk of the transmission system that supported the central dispatch. Under the new arrangement, they will lose these special payments, but the transition payments will account for that loss. 48/ All of these payments are based on estimates of the changes effected by the restructuring and are subject to unanimous agreement by the Transmission Providers. Absent unanimous agreement, they may unanimously agree to submit to mediation or arbitration. Otherwise they may seek relief with the Commission, but are tied to the principles of the transition payment formula and may only challenge the input estimates.

Protests and Commission Response

Modifications to Existing Agreements

A number of intervenors (e.g., Electric Power Supply Association (EPSA), Sithe) oppose the proposal to increase the

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47/ Attachment H to the New York ISO Tariff details the Native Load TCCs, as follows:

ConEd	11000 MW
NYSEG	2160 MW
Niagara Mohawk	2150 MW
NYPA	4700 MW

48/ The transition payment is intended to reflect the sum of the net reduction in revenue resulting from the termination of existing wheeling agreements and congestion payments to be made under LBMP less the sum of (1) revenues from sale of TCCs,(2) value of TCCs that are not sold based, in part, on the value of maintaining existing contracts in lieu of converting to TCCs, and (3) transmission revenues from off-system sales.

charges under grandfathered contracts to include ancillary service charges and marginal losses. HQ adds that the Transmission Providers should not be permitted to interfere with existing contracts negotiated in good faith, that contain specific losses provisions. HQ contends that the problem is more acute with respect to contracts subject to the laws of Quebec which do not permit contracts to be reopened without the consent of all parties. 49/ Sithe argues that the Commission has already rejected marginal losses for these types of agreements. 50/

Sithe also complains that the Member Systems' proposal to credit the overrecovery in marginal losses to the scheduling Charge provides no relief to customers served under existing contracts because they do not pay the scheduling charge.

Member Systems contend that it is an open question as to whether or to what extent existing contracts include losses and ancillary services because there has been no Commission determination that they are included. Member Systems state that, to the extent a filing is required to change these contracts, its proposal in this docket constitutes such a request. Finally, Member Systems state that, to the extent the existing contracts prohibit unilateral changes, the Commission may allow such changes in the pubic interest as it did when it made its findings in Order No. 888 to allow contracts to be modified to include stranded cost recovery.

Notwithstanding Member Systems' claim that their existing agreements may permit changes with respect to marginal losses, 51/ we agree that it is inappropriate to increase the rates under existing bilateral agreements with respect to losses or any other rate component generically. To the extent that the existing agreements permit unilateral rate increases, Member Systems are free to propose amendments changing the rates in existing agreements. Any concerns that a customer has with respect to such a rate change can be addressed in the separate proceeding under Section 205 or 206.

We note that a number of the existing contracts at issue here are between and among Member Systems themselves and, therefore, these parties have already mutually agreed to change

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49/ HQ Protest at 9 (Filed March 19, 1998).

50/ Sithe Protest at 7 (Filed February 6, 1998); Sithe Limited Response at 6-7 (Filed March 17, 1998).

51/ Member Systems Answer at 11 (Filed March 27, 1998).

those agreements. To simplify the amendment process with respect to these intra-Member Systems' contracts, we clarify that, while a filing under Section 205 or 206 is required, the filing will serve the purpose of formally amending those contracts to reflect Member Systems' express agreement in this regard. To further simplify the amendment process, we shall direct Member Systems to make a single filing to amend each of these intra-Member Systems' agreements and to adopt a simplified and uniform amendment form which simply codifies the proposed treatment of marginal losses and ancillary services.

Sithe also complains that customers served under existing contracts must schedule energy the day before and settle any real-time deviations through the spot market. Sithe complains that this is an improper penalty.

As with other aspects of grandfathered contracts, Member Systems must adhere to the existing terms of those contracts. If those contracts have different scheduling terms or deviation settlements, the ISO must honor them until such time as the agreements are modified pursuant to Section 205 or 206.

IPPNY contends that the grandfathering proposal is unclear as to whether other aspects of existing contracts will be affected by the restructuring, e.g., whether a generator that sells power under an existing contract which does not require the generator to obtain replacement power during an outage will now be responsible for doing so.

Member Systems clarify that their intent was that all aspects of the existing agreements other than those identified in this filing were to be unchanged.

Option to Convert to Tariff Service

EPSA also argues that grandfathered customers should have more time to consider whether to convert to tariff service. Sithe shares these concerns. We believe that there will be sufficient time between the date this order is issued and the date that the ISO commences operation to permit customers under existing contracts to consider their options and make an election.

Grandfathering of Bundled Retail Loads

MEUA contends that the Transmission Providers should be placed under the New York ISO Tariff and pay the same rate as other users. As we noted in PJM, 52/ it is appropriate for Member Systems to file a form of service agreement that does not require the Member Systems to effectively pay itself for transmission service over its own transmission system. However, we find that the service agreement that will apply to the Member Systems' transmission service must clearly express that, as a customer under the New York ISO Tariff, each Member System will be obtaining transmission services from the other Member Systems and from its own transmission system in accordance with the rates, terms and conditions of the New York ISO Tariff. In addition, we direct the New York ISO to adopt billing procedures for Member Systems that show the development of the charges under the New York ISO Tariff, even though the Member Systems will not be formally paying for such transmission service, in order to clearly identify each Member System's cost responsibility.

Grandfathering of Service Agreements under Individual Tariffs of the Transmission Providers

MEUA also seeks clarification that service agreements under an individual transmission provider's open access tariff are grandfathered transactions. MEUA complains that some Transmission Providers have indicated that all service agreements under their individual tariffs will be transferred to the ISO Tariff without grandfathered rights, e.g., without being awarded TCCs for the term of their existing firm service agreement. MEUA notes that this proposal is in direct contrast to the Transmission Providers' failure to place themselves under the revised tariff. 53/

Member Systems initially stated that service agreements under their individual open access tariffs would be incorporated into the terms of a grandfathered transmission agreement, even though the individual tariffs would be superseded. 54/ More recently, Member Systems contend that service agreements under their individual open access tariffs will not be grandfathered to the extent they were executed after this filing was tendered. 55/ It appears that this dispute involves services that would have

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52/ 81 FERC at 62,250.

53/ MEUA Protest at 7 (Filed June 19, 1998).

54/ ISO Tariff, Volume I, note 16 at 15.

55/ Member Systems Answer at 5-6 (Filed July 7, 1998).

qualified for grandfathering had MEUA not, in the interim, placed itself under the tariff. Another aspect of this dispute is whether and to what extent this issue is resolved under the terms of settlements between MEUA and the two of the Transmission Providers.

We shall place the dispute concerning MEUA's services under the Member Systems' individual open access tariffs before a settlement judge and, in this order, will make only a single clarification that may assist in the settlement of this dispute. We view the grandfathering provisions of the Member Systems' proposal as an acceptable method to recognize long-term firm commitments in existence on the date the ISO commences operations. Between the date that the Member Systems made this proposal and the date it becomes effective, their obligation to grant requests for service under their individual tariffs was undisturbed and, therefore, we would expect that any service agreements under those tariffs would be existing commitments.

Transition Issues

We shall neither accept nor reject Member Systems' proposal for Transition Payments among them. We note that this is a different result than we reached with respect to an element of the NEPOOL restructuring that was also labeled a transition plan and which we summarily rejected. However, there appear to be some differences between this proposal and the one we rejected in NEPOOL. For example, this proposal involves payments among Member Systems only, in contrast to NEPOOL's proposal which impacted other transmission users. Also, this proposal accounts for the Member Systems' agreement to terminate existing transmission agreements, not to reprice transmission services that would continued to be provided under existing contracts.

While we believe that it may be reasonable for the Member Systems to agree among themselves to make transition payments to reflect the termination of otherwise enforceable agreements, we have insufficient information to approve the proposal at this time. Most importantly, Member Systems have provided no information as to the amount of these payments and their impact on the revenue requirement that transmission customers will pay. We shall therefore defer action on this aspect of the proposal and will direct Member Systems to provide additional data showing the amount of the transition payments, the derivation of the payments according to the proposed formula and the impact on transmission rates that will be paid by other customers of the New York ISO.

4. Generation Reliability Issues

Description

As currently proposed, the NYRSC will specify reliability rules that the ISO will follow in operating the transmission system. As presently planned, the NYRSC will also establish a state-wide installed capacity (i.e., generation capacity) requirement. The proposed ISO Tariff places responsibility on the ISO to apportion that requirement among all LSEs in a manner that takes into account the location of Installed Capacity 56/ and to monitor compliance with these requirements. These requirements are to be imposed on an annual basis, i.e., each LSE will be required to maintain during the applicable year installed generation capacity equal to its peak load plus a reserve margin (currently around 18%).

The New York ISO Tariff states that LSEs may choose to have the ISO facilitate a market for obtaining installed capacity using bids from generators or interruptible loads. The tariff also provides that generators outside the NYCA can be used to meet the installed capacity requirements, but only up to "the level that the ISO determines these resources can reliably supply to the NYCA at the required location." 57/ If an LSE is capacity deficient (i.e., fails to meet its obligations during the annual period), it is subject to a deficiency payment which is three times the ISO's levelized embedded cost of a new combustion turbine. 58/ Member Systems state that 18% installed reserve margin is currently in place under the New York Power Pool Agreement and the ISO Tariff extends this requirement to every LSE in order "to ensure the continuation of the current level of reliability under a retail access environment." 59/

Protests and Commission Response

56/ ISO Tariff, Volume I at 31.

57/ ISO Tariff, Volume III, Sheet No. 37.

58/ ISO Tariff, Volume I at 32.

59/ Member Systems Answer at 103 (Filed March 2, 1998).

Imposition of Installed Capacity Requirement Through Transmission Tariff

MEUA opposes the imposition on installed reserve requirements through the New York ISO Tariff. We agree that installed generation reserve requirements, as opposed to operating reserve requirements, involve generation reliability matters, and such a requirement cannot be imposed as a condition of obtaining transmission service. However, we have already directed Member Systems to sever the transmission tariff and other ISO functions into two separate rate schedules. This addresses the procedural aspect of MEUA's concerns.

Imposition of Installed Capacity Requirement to All Load-Serving Entities

A number of intervenors (e.g., MEUA) also object to a requirement that all LSEs maintain specific installed capacity requirements. HQ complains that the installed capacity requirements and other critical elements of the future operations in New York are deferred to the NYRSC, which is dominated by the Member Systems. HQ states that the Commission should exercise its vigilance to avoid misuse of power and discrimination. 60/ Member Systems respond that this requirement is simply an extension of the current requirement that each Member System adhere to as part of the generation reserve sharing agreements.

We addressed a similar matter in PJM, where intervenors had complained that a requirement that all LSEs join in reserve sharing arrangements was incompatible with the emerging competitive marketplace. In PJM, we determined that it was reasonable to impose this requirement on LSEs only to the extent that they would be making purchases through the pool's spot market (PJM PX). We reasoned that the PJM Transmission Providers had committed to make all of their resources, to the extent not committed to serve native load or to make bilateral power sales, available to the PJM PX. We noted that, absent a contractual obligation for all LSEs to contribute installed capacity to the pool, the competitors of the PJM Transmission Providers, to the extent they participated in the PJM PX spot market, could rely unduly on the PJM Transmission Providers' generation resources.

We accepted PJM's proposal based on the specific facts presented there, "particularly the fact that this requirement applies only to [load]serving entities] that choose to purchase

60/ HQ Protest at 10 (Filed March 19, 1998).

from the PX and that will be effectively back-stopped by the [PJM Transmission Providers'] available generation capacity" 61/ as well as the preference of the state commissions within the PJM region that the traditional reliability aspects of the pool continue, at least during the transition to retail access "when suppliers unpracticed in the area of reliability planing will be testing the waters of as many as five different retail competition programs." 62/

We note that there are some factual similarities and differences between this proposal and PJM. Like PJM, the requirement for LSEs to meet an installed capacity requirement has the support of the state commission and will be administered by the ISO. However, unlike PJM, it is not being imposed through a power pooling agreement (which was called the Reliability Assurance Agreement in PJM). Indeed, Member Systems have not proposed to continue a power pooling arrangement which would, among other things, provide all pool members with a voice in pooling matters through voting rules that do not permit any pool member to exercise undue influence. 63/ Instead, the imposition of an installed capacity requirement would arise in the context of a universal reliability rule, rather than a reserve sharing agreement. Also, the requirement is not limited to those LSEs that elect to purchase power through the spot market, nor does it appear that there is a requirement for the Member Systems to make their generating capacity available to the spot market when not being self-scheduled to load or used to support bilateral sales.

We shall reserve judgement on whether and to what extent it is appropriate to impose an installed capacity revenue requirement on LSEs outside the context of a power pool arrangement until Member Systems tender their revised filings in response to this order. We shall direct Member Systems to provide further justification for their proposal given our findings in PJM as to the criteria under which an installed capacity requirement might be extended to LSEs. Alternatively, Member Systems may revise their proposal to address these concerns.

61/ 81 FERC at 62,277.

62/ Id. at 62,278.

63/ In PJM, there were two voting blocks and action required 2/3 approval in each block. The voting rules in the first block were one member, one vote. The voting rules in the second block were based on relative load, with voting shares capped at 25%. Id. at 62,277-8.

Requirement that Installed Capacity Requirement be Assigned on a Locational Basis

HQ opposes the locational limitations on resources which can satisfy the installed capacity requirement. 64/ HQ characterizes these as import quotas which serve only to insulate internal generators from outside competition, relegating outside generators as sellers of economy energy only. HQ argues that the only reasonable limitation is that resources be supported by transmission reservations. 65/

Member Systems state that HQ's proposal cannot be accommodated under the New York ISO Tariff because it eliminates the concept of physical transmission rights and relies solely on financial rights. Member Systems state that, for this reason, no market participant can ensure that a particular generator's capacity is deliverable to a particular location by reserving transmission. Member Systems also state that no decisions have yet been made as to the locational requirements for installed capacity and they will be made by the ISO to meet the reliability criteria established by the NYSRC.

Because the extent to which installed capacity requirements will be established on a locational basis has not yet been determined, this issue is not ripe for resolution. However, it is our understanding that the installed capacity requirement included in the present NYPP pooling agreement is not determined on a locational basis and, in fact, we are unaware of any pooling agreement that incorporates such an approach. We clarify that, to the extent that the ISO exercises its authority to establish locational requirements for those entities that are subject to an installed capacity requirement, it must make a filing detailing those requirements and providing justification for its proposal. Affected parties will have an opportunity to raise their concerns at that time.

64/ HQ cites to the Member Systems' Market-Based Rate Application, Volume I, at 11 (Filed August 15, 1997), as imposing locational requirements of 90% instate, 68% related to NYC load located in NYC, and 89% related to Long Island load located on Long Island.

65/ HQ Protest at 7 (Filed March 19, 1998).

Imposition of Installed Capacity Requirement on an Annual Basis

Coalition for a Competitive Electric Market (CCEM) argues that the installed capacity requirements should be a monthly obligation, not an annual obligation. CCEM argues that, with the advent of retail access, loads will change more frequently and dramatically, and an annual requirement is inconsistent with this market. IPPNY complains that an annual installed capacity requirement is inconsistent with a competitive market and impedes retail access because entities will have to make commitments that may not materialize. IPPNY also complains that an annual requirement imposes poor price signals because it spreads the cost of capacity over the entire season. IPPNY argues that a system which permits value to change in on-peak and off-peak periods, and which assigns different penalties on these bases, would be preferable. Member Systems respond that a monthly commitment would provide the ISO with insufficient lead time to verify whether LSEs have adequate installed reserves and to address any shortfalls. They also contend that, if the installed capacity requirement were to vary each month on the basis of monthly loads, higher reserves would likely be required and generation maintenance flexibility would be reduced.

We share the intervenors' concerns that an annual assessment of installed capacity requirements may no longer be reasonable, particularly once retail access is introduced. We agree that the system's installed capacity needs are appropriately assessed on an annual basis because the annual peak loads are the driving factor in determining those needs. However, in a circumstance where loads can shift suppliers on a monthly basis, a requirement that each affected supplier provide capacity based on its individual annual peak fails to take into account that more than one supplier may be serving the same load during the year. Take, for example, a situation where total system load is 100 MW and the installed capacity requirement for that load 118 MW. If there are two suppliers and each serves that load for half of the year, each will have an individual annual peak of 100 MW and an installed capacity Requirement of 118 MW, resulting in a total requirements of 236 MW, twice the system needs. While this example is extreme, it illustrates the flaw in Member Systems' proposal. We shall require that this requirement be revised to ensure that, as a result of changes among suppliers during the year, it does not impose installed capacity requirement on LSEs as a group that exceeds the system's total needs.

Criteria for Accreditation

A number of intervenors question the criteria which will be used to accredit generation as meeting the installed capacity requirement. For example, IPPNY complains that the availability requirements of each generator is based on a comparison with other generators of the same type rather than all generators available to the system. IPPNY contends that this tends to overstate the value of units with low availability experiences when compared to other classes that have better performance. Member Systems state that the accreditation procedures are based on historical practice and changes would have to be carefully reviewed in light of "possible interaction with the reserve requirement and its potential effect on diversity of generation and fuel mix within the state." We cannot conclude on the basis of the information provided whether the accreditation criteria are reasonable. We shall allow intervenors to pursue this issue in the hearing we have ordered.

Capacity Benefit Margin

Athens expresses concern that there is nothing in the tariff to prevent the transmission providers, operating through the NYSRC, from removing intertie capacity from available transmission capacity (ATC) under the guise of generation reliability for a Capacity Benefit Margin. Athens contends that it would be inappropriate to continue this practice, if it has in fact been an NYPP practice. Member Systems respond that, when considering installed capacity located outside of the control area, consideration must be given to the fact that "power pools have been able to reduce the amount of installed capacity they require" by withholding interconnection transmission capacity in reserve for contingencies. 66/

We note that the ISO will be responsible for computing ATC. If and when it makes a capacity benefit margin adjustment in computing ATC, it will be required to explain and justify its calculations.

C. Market Rules

Locational Based Marginal Pricing and Energy Markets

As noted earlier, Member Systems propose a locational-based marginal pricing (LBMP) system, which is similar in many respects

66/ Member Systems Answer at 19 (Filed April 4, 1998).

to the locational marginal pricing system in PJM. 67/ Under the current proposal, separate energy prices would be determined hourly for each node (or bus) in the control area. The price at each node would equal the marginal cost to the ISO of producing and delivering energy to the node, based on the bids submitted in an energy auction. In determining marginal cost, the ISO would consider the energy bids submitted by generators and the marginal transmission losses and congestion to move energy from source to load. As noted earlier, the locational energy prices are used to determine the transmission usage charge.

The proposal would create two sets of energy markets: day-ahead markets and real-time markets. The two-market system is referred to as a two-settlement system, since there are separate financial settlements for each of the two markets.

Day-Ahead Market

The ISO will develop a state-wide load forecast based upon its own forecast and forecasts submitted by LSEs. The ISO will compute a day-ahead unit commitment schedule to accomplish four goals: (1) supplying energy to satisfy all accepted buyer bids in the day-ahead market; (2) providing sufficient ancillary services to support the energy purchased; (3) committing sufficient capacity to meet the load forecast and provide ancillary services; and (4) meeting all bilateral schedules submitted day-ahead. The schedule is developed with the objective of minimizing the total cost of generation, operating reserves, and regulation service subject to transmission and other constraints. Each individual's generation, transmission and withdrawal will be considered proprietary and not be posted publicly.

In developing weekly plans, the ISO may determine that it will need long time start-up generators for reliability. If those units are committed, they will accrue start-up revenues until such time the ISO determines that this generator will not be needed. In general, generators with long start-up periods will be chosen on a least cost basis.

Generators will submit three-part energy bids reflecting: (1) start-up; (2) minimum load; and (3) energy. Bids to purchase energy must indicate the hourly quantity in MW by point of withdrawal and indicate prices at which the transaction will be voluntarily curtailed. Bilateral transactions must identify the

67/ See PJM, 81 FERC at 62,253.

hourly quantities in MW and the points of injection and withdrawal.

In the day-ahead market, the ISO determines the amount of energy scheduled to be produced by each generator and the day-ahead locational prices (LBMPs) at each location based on bids submitted by generators and loads. Generators are paid the applicable day-ahead LBMP for their accepted generation bid quantities. LSEs pay the applicable day-ahead LBMP for their accepted load bid quantities. This first financial settlement is determined a day ahead of the real-time operations.

Real-time market

In the real-time market, after the close of the day-ahead market and up to 90 minutes before the dispatch hour, generators and LSEs may submit additional bids or revise existing day-ahead bids for the upcoming dispatch hour. Bilateral transactions scheduled day-ahead may be modified, and/or new bilateral transactions can be scheduled. In real-time, the ISO runs a dispatch every 5 minutes to minimize total incremental energy costs of meeting load subject to reliability constraints and maintaining scheduled interchanges with other control areas. At the end of each hour, the ISO also calculates the average of the 5-minute LBMPs.

The real-time settlement deals only with deviations from the day-ahead schedule and is based on the applicable real-time locational price. For example, buyers that received more energy than they had scheduled the day before pay for the difference at the applicable real-time prices. The real-time payment made to generators is more complicated. If a generator injects energy less than or equal to the amount it had scheduled, it pays the ISO the real-time LBMP for the energy reduction. If the generator injects more energy than it had scheduled and this deviation is consistent with the ISO's instructions, it is paid the real-time LBMP price. However, if the excess generation is not in accordance with the ISO's instruction, the generator is paid nothing for the excess energy.

When a dispatched generator incurs start-up and minimum generation costs, it will be entitled to an additional payment to the extent its revenues from energy sales and other ISO-administered markets are less than its total start-up, minimum-load, and energy bids. As noted earlier in this order, these supplemental payments are recovered pro rata from all loads through the transmission scheduling charge.

Calculation of LBMP and Congestion Costs

The calculation of LBMPs under the New York ISO Tariff is similar to the calculation of locational prices as adopted by PJM, although PJM is a single (real-time) settlement system. 68/

Real-time and day-ahead schedules and LBMPs are determined in much the same way with only minor differences. The main difference is in terms of generation costs. In developing the day-ahead schedule, the ISO must consider whether to start up generators, and thus how to minimize energy, start-up, and minimum load costs to reliably meet load. However, in real-time, start-up decisions have already been made. Therefore, start-up and minimum load costs need not be considered in determining the real-time dispatch. In real-time, the ISO considers how to minimize only energy costs. The LBMP that is derived for any location in either real-time or day-ahead shows the marginal cost to the system of delivering one more MW of electricity to that location inclusive of losses and congestion.

Member Systems state that, due to metering problems at points of withdrawal, LSEs will be charged a "zonal" LBMP. This treats a number of points in one area as if they were one point. The zonal LBMP is equal to a weighted average of generator bus LBMPs within each zone, where the weights are determined by the ISO. There will initially be 11 zones and thus 11 LBMP prices each hour for points of withdrawal.

Protests and Commission Response

LBMP Pricing

CCEM requests that the Commission deny approval of the LBMP system proposed by the Member Systems on the grounds that it is a black box, too complex, ill conceived, and does not confer transmission price certainty. 69/ MI make many of the same arguments. They say that this approach is untested and that LBMP hurts end-users in the eastern part of New York state because the prevailing power flows are west to east. MI prefers an average

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68/ Id.

69/ CCEM Protest at 11-18 (Filed February 6, 1998). Transmission price certainty will be addressed below in 4.7.

cost method which shares congestion costs among all users pro rata. 70/

CCEM and others made these same arguments in PJM and we shall deny these requests for rejection on the same grounds here. 71/ Besides reiterating the points we made in PJM, we note that Member Systems' proposal includes features that were not included in PJM, i.e., a multi-settlement system and the opportunity for bilateral customers to submit incremental and decremental energy bids. These two features provide additional price certainty.

CCEM also complains that transmission customers do not have the option of specifying the congestion price they are willing to pay to avoid curtailment and requests that customers be given such an option. The Member Systems respond that software is not currently available that would permit transmission bidding (and thus, allow the ISO to curtail transmission service based on price). However, the Member Systems state that developing the software could be considered if market participants are willing to bear the development costs. We will require the Member Systems to study the feasibility and cost of transmission bidding in consultation with stakeholders, and to report back to us within six months.

Zonal LBMP Pricing

The New York Commission states that the zones should be revaluated periodically to ensure that nodal LBMPs within each zone are similar. 72/ CCEM is also critical of zonal pricing and argues that, if LBMP is implemented, nodal pricing must be applied to both buyers and sellers. 73/ Cogen also believes LSEs should pay a nodal price, not an averaged zonal price. Cogen complains that, if variance in actual nodal prices within the zone is high, some are hurt while some benefit, thereby providing the wrong incentives for load reduction. Cogen wants a commitment to move to nodal prices for loads in the future. 74/

70/ MI Protest at 24-26 (Filed February 6, 1998).

71/ See PJM, 81 FERC at 62,255-58..

72/ New York Commission Comments, Appendix at 3 (Filed February 6, 1998).

73/ CCEM Protest at 17 (Filed February 6, 1998).

74/ Cogen Comments at 4-5 (Filed February 6, 1998).

We note that the Member Systems, in principle, would like to adopt nodal pricing for loads, but metering limitations prevent adopting it at present. However, the Member Systems do not seem to have any timetable in mind for installation of metering equipment so that LSEs can be charged nodal LBMPs.

We shall require that the New York ISO submit to the Commission a plan for the installation of the metering equipment that will implement the nodal pricing that has been proposed by Member Systems. In developing the plan, the ISO should consider whether meters should be installed for all loads, or alternatively, only for loads willing to pay for the meters. We will revisit the New York Commission's concern about the need to update zones that may be in place for some time after we receive the installation plan. 75/

LBMP Information

CCEM argues that all market participants should have full access to any information used in the market. This includes nodal price data, models, forecasts of load and prices, and associated software, etc. CCEM argues that this could be hourly data in many instances and should be kept for at least three months afterwards.

We agree that the ISO should maintain data on prices and load forecast for at least three months and should make these data available to market participants. Markets operate better under full information, and the availability of this information would help the market function more efficiently. We will also require that all information regarding energy bids be kept confidential for six months to help prevent collusive behavior. After a six-month delay, information on individual bids should be released to the public to help interested parties monitor the market.

Three Part Bids

New York Commission expresses concerns about the treatment of start-up and minimum load costs. New York Commission would prefer a system that reflects start-up and minimum load costs in the LBMP pricing methodology for recovery through energy charges

75/ We clarify that our approval of Member Systems' proposal to adopt nodal pricing does not indicate a belief that other types of congestion management plans are unreasonable.

rather than recovering these costs separately from all loads. 76/ New York Commission is concerned that Member Systems' proposal could lead to competitive advantages for some generators and may understate prices for electricity. 77/ IPPNY suggests a bidding process where suppliers may bid prices in conjunction with bids for minimum run and down times. 78/ IPPNY complains that Member Systems' proposal is unreasonable because it shifts the additional costs for start up and minimum run from the generators to all customers. Another intervenor critical of multi-part bidding suggests that the bid structure be changed to a one-part bid with minimum run time and a minimum down time.

We note that Member Systems' proposal in this respect is similar to the approach used in PJM. Deciding to commit generators may involve start-up and minimum load costs. These costs do not vary with the amount of energy subsequently produced above the minimum load. Multi-part bidding allows generators to inform the ISO of these separate costs. Thus, multi-part bidding allows the ISO to obtain detailed and complete information with which to develop least-cost energy schedules.

We will accept the Member Systems' proposal to recover these costs pro rata from all transmission customers regardless of the type of transaction (bilateral or spot market). Intervenors argue that bilateral load should not pay for start-up and minimum load cost of generators selling into the ISO's energy market, since these costs are attributable solely to the spot market and not at all to bilateral transactions. We agree with the Member System's contention that start-up and minimum load costs support both energy and ancillary services such as regulation and operating reserves, as well as redispatch to alleviate transmission congestion. Ancillary services are necessary for reliability, and all loads benefits from reliable operation of the transmission system.

Since all loads benefit from the system's reliability and since loads from both ISO and bilateral markets may benefit from congestion management and ancillary services, it is not unreasonable that these costs be recovered through the scheduling charge from all loads.

76/ New York Commission Comments at 13 (Filed February 6, 1998).

77/ New York Commission Comments at 14 (Filed February 6, 1998).

78/ IPPNY Protest at 34-35 (Filed February 5, 1998). See also, Cogen Comments at 9 (Filed February 6, 1998).

Storm Watch Conditions

New York Commission is also concerned with bidding and dispatch under storm watch conditions. 79/ When the system is operated under storm watch conditions, the system is redispatched to remove load from transmission lines that are vulnerable to outage. This redispatch will raise the cost of energy in the areas that are being protected from transmission outages. As proposed, the costs of a storm watch redispatch would be recovered from all transmission users through the scheduling Charge. New York Commission contends that storm watch conditions are focussed in certain areas with greater frequency and predictability (downstate New York), and these areas should bear the costs associated with such conditions. New York Commission states that, because day-ahead commitments are made without taking into account the possibility that there may be storm watch conditions the next day, there is an incentive for buyers, anticipating possible storms the next day, to lock in day-ahead to keep from paying these higher prices and burden all transmission customers with the cost of the next day's storm watch redispatch. New York Commission argues that this incentive would be removed if the ISO were to factor potential storm watch conditions as a part of the day-ahead commitment.

While we understand the New York Commission's concerns, we believe that the New York Commission's proposed solution is also problematic. While it is reasonable to expect the ISO to reflect the fact that storm watch conditions which have been formally invoked in accepting schedules in the day ahead market, we do not believe it is reasonable to place the burden of predicting the weather and the likelihood of storm watch conditions being invoked the next day on the ISO. If the ISO's weather predictions proved incorrect, there would similarly be a pricing impact that reflects expectations that did not occur.

While we are not prepared to adopt the New York Commission's alternative, we shall direct the ISO to study this issue further and provide an analysis of the present method and possible options after one year's experience in dealing with storm watch conditions.

Disparate Treatment of External and Internal Generators

HQ complains that one of the market rules distinguishes between suppliers located inside New York and outside New York.

79/ New York Commission Comments, at 15 (Filed February 6, 1998).

80/ Suppliers involved in bilateral transactions may provide the ISO with a "decremental bid" which is the price at which the ISO will curtail the delivery from the supplier and substitute a delivery from the spot market. When the bilateral transaction involves a generating resource located within the control area, this transaction is treated as a purchase of substitute energy by the supplier. The savings results from purchasing from the spot market instead of generating accrues to the supplier. For suppliers outside of New York, the decremental bid price tells the ISO at which price the external transaction is curtailed, i.e., there is no substitution of energy from the real-time market.

As a practical matter, the New York load would continue to be served from the spot market but this would become a transaction between the purchaser and the spot market. Thus, the supplier (here, HQ) would be out of the picture. Outside suppliers can avoid curtailment in all circumstances by submitting a very low decremental bid; however, this precludes them from accessing lower cost energy from the spot market when available. HQ contends that this discriminates against non-New York generators by not giving them the option of cost savings substitution. Member Systems respond that their proposal is reasonable because the ISO cannot accommodate a substitute purchase with external generators due to dynamic scheduling concerns.

We agree with HQ that Member Systems have not justified this aspect of its proposal, which appears discriminatory. We are not persuaded by the Member Systems' scheduling concerns because, whether or not a substitute purchase is obtained, the ISO must curtail HQ's generation and the substitute purchase becomes an intra-control area transaction. There is no difference in scheduling between the two control areas under either approach. We shall direct Member Systems to revise the proposal to treat external suppliers the same as internal suppliers.

Failure to Pay Generators For Excess Generation

IPPNY protests Member Systems' proposal not to pay for power delivered above the amount scheduled or requested by the ISO. IPPNY claims that this is discriminatory because some sources do not have the telemetry or other equipment necessary to respond to the ISO's automatic instructions and that generation can vary for reasons beyond the control of the generator. IPPNY claims that generators hurt by this are intermittent, small hydro, and solar

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80/ HQ Protest at 4-6 (Filed March 19, 1998).

generators. IPPNY concludes that LBMP pricing will provide an incentive for generators not to produce excess energy because when over-generation occurs, prices fall. 81/

Member Systems respond that overgeneration can seriously affect reliability and cause damage to other generation and transmission equipment. Member Systems add that deviations in load are more easily accommodated than variations in generator output.

We disagree with the intervenor's assumption that, because an increase in generation would cause the LBMP at that particular generation bus to decrease, this would take away the incentive to overproduce. First, a generator overproducing -- particularly one without the capability to communicate through telemetry with the ISO -- may not receive a price signal fast enough to avoid a line loading problem. Moreover, falling prices may not create any incentive to avoid overgeneration because the revenue impact of overgeneration is affected by the volume of the power delivered, not just the change in unit prices. For example, if the generator would not have been dispatched at all, the revenue impact is the amount of excess generation times the entire LBMP price, not the differential between the prices that occur with and without overgeneration. We agree with Member Systems' that strong rate disincentives are needed to induce generators to be vigilant in avoiding overgeneration and shall accept this proposal.

Ancillary Services

A separate market will exist for operating reserves and regulation and frequency response services. 82/ As noted earlier, voltage support is contracted separately under cost-based rates. Below, we discuss these three services.

Voltage Support Service

As noted earlier in this order, each supplier will receive a cost-based payment, which includes a capacity charge as well as compensation for opportunity costs reflecting the foregone revenues from not participating in the energy market. When a non-utility generator (NUG) provides these services, the ISO

81/ IPPNY Protest at 36-37 (Filed February 5, 1998).

82/ Under the ISO Tariff, energy imbalance service is settled through the spot market.

contracts with the entity that is entitled to the output of that unit, not the owner of the unit. 83/

Sithe complains that NUGs will not be compensated for voltage support services even when they supply it. 84/ However, we do not find the Member Systems' proposal troubling. As we understand it, the ISO will pay the party with whom it contracts. It is reasonably expected that the contracting party is the entity entitled to the output of the generator. If a NUG believes that its contracts with purchasers permit it to contract directly with the ISO to provide voltage support, we expect that the ISO would allow the NUG to participate in providing these services.

HQ claims it has been a supplier of voltage support for New York up until now, but under the New York ISO Tariff, out of state generators would not be permitted to supply it. Voltage support is typically supplied locally for technical reasons. It is usually not feasible to import voltage support from a significant distance. However, HQ's DC intertie may very well allow it to provide voltage support in the NYCA and, apparently, it has done so in the past. We shall direct the New York ISO to examine this issue and consult with HQ about the feasibility of adding HQ as a supplier and report back to the Commission within 90 days of commencement of the ISO.

Ancillary Service Markets

The markets for regulation and frequency response and operating reserve are conducted in much the same fashion. The ISO will offer to provide these services to transmission customers, but market participants are not required to purchase them from the ISO and they can be either self-supplied or purchased from a third party. Any services that the ISO provides to customers are procured through a bid-based market. Generators bid into the various ancillary service markets, and the ISO stacks the bids for a particular service in ascending order. The clearing price for capacity (availability) for a particular service is equal to the highest accepted bid price for that service. Unlike the price of energy, there are no locational prices for capacity to supply ancillary services (except for certain spinning reserves, discussed below). Instead, a single price is paid to all suppliers of a given ancillary service in an hour.

83/ See ISO Tariff, Volume III, Rate Schedule 2 at 88.

84/ Sithe Protest at 24-25 (Filed February 6, 1998).

Parties bidding into the ancillary services markets submit bids for the capacity they wish to make available for any particular service simultaneously with bids into the energy market. The bidders cannot submit bids using capacity that has already been bid into other markets. For example, if a generating unit with a capacity of 100 MW bids 80 MW into the energy market, it can only bid up to 20 MW of capacity for use in the spinning reserves market. Similarly, if the 20 MW is bid into the spinning reserves market, it may not also be bid into another ancillary service market.

Regulation and Frequency Response (Load Following)

Generators bidding to provide this service must be located in the NYCA, meet metering requirements, and be able to respond to the ISO's telemetry signals. Bids must specify MW capability reserved, response rate (MW/min), bid price, and location. As with energy, there are day-ahead and real-time markets. Suppliers receive availability payments plus an energy payment. The availability payment equals the product of the market clearing price for capability and the performance index of the generator 85/ and the regulation capability of the generator offered to the market. The energy payment is equal to the amount of energy a unit has been directed to supply times the real-time LBMP for energy. Suppliers of this service who deviate from the ISO's signals pay a charge equal to the deviation in MWh times the market price for capability.

Operating Reserves

Operating reserves are classified into three categories: (1) spinning reserves; (2) 10 minute non-synchronous reserves; and (3) 30 minute reserves. Availability bids 86/ are made for each hour by potential suppliers. Any capacity made available for reserves must not be used to supply energy to the energy market or for regulation service until instructed to do so by the ISO. It is up to the ISO to make sure that reserves are "properly located electrically so that transmission constraints resulting

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85/ The performance index is a forecasted expected value of performance for generators providing regulation and frequency. This is determined by the ISO.

86/ While the availability bids themselves are not location specific, the ISO requires all generators bidding into any market to supply it with generator information which includes location. See ISO Tariff, Volume III, Attachment E, at 168.

from either commitment or dispatch of units do not limit the ability to deliver energy to loads in the case of contingency." 87/ The ISO is to minimize the cost of meeting these reserve requirements. At least 50% of the 10 minute reserve requirement must be met by spinning reserves. 88/ Like the market for regulation service, there are day-ahead and real-time markets for each of the three operating reserve types.

Operationally, in real-time, the ISO may need to reduce the output on certain units to provide spinning reserve capability. 89/ If so, each such unit will receive compensation for the MWs backed down based on marginal lost opportunity cost. The per MW opportunity cost of a unit is the difference between the applicable real-time LBMP and the unit's real-time energy bid. The marginal lost opportunity cost is determined by the unit with the highest opportunity cost and may be determined locationally if transmission constraints exist.

Only New York generators and interruptible load may make availability bids into spinning reserve markets. Units that are called upon to produce energy are also subject to performance penalties if they do not perform as obligated, i.e., forfeiture of part of the availability payment, compensation for the ISO's replacement power costs, and possible penalty charges.

For other reserves, suppliers need not be in the New York Control Area, but must hold sufficient transmission rights to deliver the reserves. If a unit providing these other reserve costs incurs start-up and minimum load costs which are not fully recovered through availability and energy payments, that unit is paid for unrecovered costs via an uplift payment much like the energy market.

Intervenors argue that the ISO should not preclude generators outside the control area from supplying regulation and spinning reserves because such restrictions may tend to reduce competition and raise the costs of procuring these services by excluding potentially lower cost sources from outside the control

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87/ ISO Tariff, Volume III, Rate Schedule 5 at 109.

88/ Id. at 112. While it is possible the ISO may use 10 minute spinning reserves as a substitute for 10 minute non-spinning reserves, the Tariff is silent on whether the ISO can use 10 minute spinning reserves as a substitute for 30 minute non-spinning reserves.

89/ ISO Tariff, Volume III, Rate Schedule 5 at 112.

area. However, there may be technical limitations that limit the reliability value of regulation and spinning reserves supplied from resources from outside the control area. We shall not require that the ISO rely on external supplies at this time, but we direct the ISO to evaluate this option and include the results of this evaluation and its recommendations in a report that we shall order below.

We shall accept the ancillary services market aspects of Member Systems' proposal in all respects but two. First, the filing is unclear regarding how the index will be computed in determining penalties for suppliers of regulation service that do not perform as instructed. Therefore, we shall direct the ISO to define explicitly the performance index associated with regulation service.

Second, in light of the experience in California, we will require that the tariff be modified to permit the ISO to procure more of a "higher quality" category of reserves and procure correspondingly less of a "lower quality" category of reserves when to do so would lower total cost. This procurement method is also known as cascading. For example, the ISO could procure more 10-minute spinning reserves (a higher quality reserve) and less 30-minute non-spinning reserves (a lower quality reserve) in the same location without reducing reliability and it should be allowed to do so if this is the cheaper alternative.

We shall also require that all information regarding bids to be kept confidential for six months to help prevent collusive behavior in ancillary services markets. After a six-month delay, information should be released to the public to help interested parties monitor the market.

Lessons from California suggest that ancillary service markets are complex, 90/ and the indications are that market designs may contain flaws which will only be discovered once the markets are in operation. Accordingly, we shall direct the ISO to submit an evaluation of the ancillary service markets after 15 months of operation.

Installed Capacity Market

90/ Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator (ISO), prepared by the Market Surveillance Committee of the California ISO, at 21.

We have discussed aspects of the installed capacity requirements for customers earlier in this order. Member Systems state that they intend to operate an installed capacity market. We believe that this is a valuable feature of their proposal. However, Member Systems have provided no details as to the operation of the market and we are unable to approve the proposal in its current form. We shall direct the New York ISO to file a detailed proposal regarding the implementation of an installed capacity market.

Transmission Congestion Contracts

Description

A TCC is the right to collect congestion rents associated with a single MW of transmission between a specified point of injection and point of withdrawal. The congestion rents come from the congestion component of the LBMPs. A TCC, as proposed by the Member Systems, is defined for a specific point of injection and point of withdrawal, and the rents may either be positive or negative. For example, consider a TCC for 1 MW between point of injection A and point of withdrawal B. If the energy price at B is $5 higher than the energy price at A (after adjusting for losses), the congestion is positive, and the holder of the TCC would receive $5 in congestion rents. Conversely, if the energy price at B is $5 lower than the energy price at A, then the holder of the TCC would pay $5 in congestion rents. A TCC gives the holder the ability to hedge against congestion costs associated with transmitting energy from point of injection to point of withdrawal. Essentially, it gives the holder the ability to transmit the amount of power specified in the TCC between the TCC's point of injection and point of withdrawal without paying congestion costs.

Initially, TCCs will be allocated to existing uses, including existing native load uses. 91/ TCCs associated with ATC remaining after honoring existing uses of the system will be distributed to the Transmission Providers based on each Transmission Provider's ownership of transmission lines connecting to the TCC's defining points of injection and withdrawal, measured in terms of MW-miles. The Transmission Providers will be required to sell residual TCCs either by auction (discussed further below) or through a direct (bilateral) sale conducted on the OASIS. The revenues from these sales will

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91/ As noted earlier, customers under bilateral contracts that elect to convert to ISO Tariff service will be awarded the TCCs associated with that contract.

be used to defray their respective revenue requirements. TCCs associated with retail native load (Native Load TCCs) are to be "released" as retail access programs are enacted with New York Commission approval; however, the terms for these releases are left for a later filing. Any TCCs associated with a grid upgrade are awarded to the parties paying for the cost of the upgrade.

Initially, the lifespan of a TCC is at least six months which corresponds to either winter or summer capability periods, but the ISO will be permitted to extend the TCC lifespan subject to the condition that it may not exceed the end of the Transition Period discussed earlier in this order. TCCs can be bought and sold like any other financial instrument or commodity. They can be exchanged either bilaterally or through the TCC auction. Any party that wishes to buy a TCC through the auction must be able to meet certain credit requirements, and a party must show that it has the funds available to pay for TCCs for which it bids.

TCC Auction Structure

An auction will be held for each six-month capability period. Transmission Providers must offer to sell in the auction all residual TCCs to the extent that they have not sold them previously through the OASIS. In addition, other holders of TCCs may offer TCCs for sale in the auction.

Because TCCs are a new financial instrument, market participants have expressed concern that they are uncertain of the economic value of TCCs. To address this concern and to help provide price discovery, the filing proposes that each auction stage may include several different rounds.

In Stage 1, there will be a minimum of four rounds of auctions. In each round, only a portion of the available TCCs, as determined by the Transmission Providers, will be awarded to bidders. The tariff is unclear whether this percentage is announced in advance. The intention is that by auctioning TCCs in increments over several different rounds, market participants will gradually obtain more accurate assessments of the economic value of TCCs. The total quantity of TCCs auctioned off over all rounds of auctions will be equal to the total number available. The fraction of TCCs to be awarded in each round will be determined by unanimous vote of the Transmission Providers. 92/ In each round, market participants may submit bids for all of the TCCs to be awarded in Stage 1. At the end of the round, the ISO will determine the market-clearing prices for TCCs and what the

92/ ISO Tariff, Volume III, Attachment M at 238.

quantity of TCCs that would have been awarded to each buyer if all TCCs offered for auction were awarded. However, the ISO will actually award a specified percentage of these TCCs to each winning bidder at the market-clearing prices. In Stage 2 there can be a variable number of rounds, and there is no requirement that any TCCs be put up for sale in this stage.

The ISO will provide information prior to the auction that may bear on the value of TCCs. Among other information, this information will include the expected non-simultaneous total transfer capability for each interface, the congestion component of each of the LBMPs over the previous 10 capability periods, and the number of hours that various transmission facilities were physically constrained. All individual bid information will be kept confidential.

There is no predetermined set of TCCs that will be made available ex-ante, and many different combinations of TCCs among points of injections and withdrawal are feasible. The ISO will run a power flow model to determine the feasibility of alternative combinations of bids for those TCCs offered through the auction, taking into account the TCCs that are outstanding with respect to existing commitments. 93/ The ISO will select the combination of TCCs with the highest aggregate bid value and award them accordingly through the auction.

All bidders who are awarded TCCs will pay the market clearing price which is determined by the auction. Because TCCs involve different points of injection and withdrawal and congestion varies locationally, the market clearing prices for various TCCs will vary.

Secondary Market

Secondary markets are expected to arise after the auction is complete. This market could take many forms, e.g., outright sales, sales for a limited time period, reassignments, or any other arrangement. After a direct sale is made, the following must be posted on the ISO's OASIS: 1) amount of TCCs in MW; 2) point of injection and withdrawal for each TCC sold; and 3) price paid for each TCC. No information is given on the identity of the buyer or the seller unless the transaction involves a residual TCC, when the name of the buyer is reported.

93/ A set of TCCs is simultaneously feasible if it would not cause any thermal, voltage, or stability violations within the NYCA. ISO Tariff, Volume III, Attachment M at 244.

Protests and Commission Response

Allocation of TCCs

Various intervenors complain about several aspects of the initial TCC allocation. Some complain that almost all TCCs will be associated with existing uses and not available for new transmission uses. Some argue that no TCCs should be associated with existing uses and should, instead, be auctioned. Others complain that the residual TCCs will be awarded to the Transmission Providers before being sold or auctioned.

Member Systems respond that the fact that many TCCS will be grandfathered simply evidences the fact that most transmission rights have been assigned. Member Systems point out that the same would be true if existing physical transmission rights were tallied. Member Systems conclude that, if these TCCs were not awarded to existing uses, including native load, it would be inconsistent with Order No. 888's conclusion that existing uses would be honored. Member Systems state that TCC availability will not be limited to Residual TCCs and that owners of TCCs will place them into the market if they have a market value.

We agree with Member Systems that there should be no surprise that most TCCs are associated with existing uses because the transmission system was constructed and operated for the purpose of serving existing needs. The initial TCC allocation simply reflects the current firm usage and does not create any new benefit for use of the transmission system that was not already in place under the Member Systems' individual open access tariffs. We also agree with Member Systems that the benefit of TCCs is that they facilitate the transfer of existing rights through a financial instrument rather than relying on the reassignment of physical transmission rights which, under the pro forma tariff, can be used to reach the same result.

We also find that the allocation of residual TCCs to the Member Systems before being sold or auctioned is reasonable. Residual TCCs are not associated with existing uses and are more properly analogized to ATC. As the owners of this ATC, it is reasonable that, as proposed, the Member Systems receive the proceeds of these TCC sales and use those revenues to reduce their transmission rates.

Potential for Oversubscription

New York Commission is concerned that TCCS awarded to existing commitments could oversubscribe the transmission system at certain constrained interfaces. It requests an examination after one year to make sure the transmission system is not oversubscribed. New York Commission contends that the plan to conduct a feasibility test to find the number and type of TCCs that are simultaneously feasible under "normal" conditions is too vague and that the timing and method of conducting this feasibility test does not appear in the filing. New York Commission also questions assumptions about how generation and transmission maintenance schedules, load growth, contingencies, and unit commitment fit into the analysis. IPPNY wants to be assured that TCCs will not be oversubscribed due to changing conditions that might affect the transmission system. This position is also echoed by Sithe.

In answer to these concerns, Member Systems offer that, if the initial allocation is ultimately determined to be oversubscribed, Native Load TCCS will be reduced pro-rata to eliminate the oversubscription, while preserving the TCCs and grandfathered rights associated with existing bilateral contracts. 94/

Member Systems' proposal addresses concerns about oversubscription. We shall direct that the ISO Tariff be revised to reflect this commitment and to clearly provide for the ISO to make the determinations about oversubscription and pro rata reductions.

Release of Native Load TCCs

New York Commission argues that the proposal should include specific language reserving the benefits of Native Load TCCs for released retail loads. 95/ CCEM wants the Commission to guide the Transmission Providers in the allocation and sale of TCCs once retail competition comes to New York. 96/ CCEM is concerned that the transmission Providers may choose to release the less valuable TCCs and keep the most valuable for themselves. CCEM advocates a code of conduct for the transfer of native load TCCs to unregulated affiliates, and recommends that the release be non-discriminatory. CCEM recommends that TCCs initially allocated to generators which are subsequently divested be released at the time of divestiture, not when retail competition is implemented

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94/ Member System's Answer at 81 (Filed March 2, 1998).

95/ New York Commission Comments at 22 (Filed February 6, 1998).

96/ CCEM Protest at 21-24 (Filed February 6, 1998).

in New York. Athens argues that released native load customers should be allowed to keep the value of the associated TCCs. 97/

Member Systems respond that these concerns are premature because this proposed tariff applies only to wholesale transactions. Member Systems note that they intend to revise the proposed tariff to accommodate retail transmission at some point in the future.

We agree that Member Systems' proposal is unclear as it relates to the "release" of Native Load TCCs, both in the context of releasing native load and in the context of divesting a generating unit that is currently used to serve native load. We also agree with the intervenors that this issue should be resolved sooner rather than later. Given Member Systems' plan to revise the proposed tariff to accommodate the retail transmission aspects of retail access, we shall direct them to include with that filing a detailed proposal for the release of Native Load TCCs.

TCCs for the Hour Ahead Market

HQ complains that TCCs are settled on the basis of the day-ahead market and there should be a mechanism that allows the use of TCCs in the hourly market. CCEM also complains that, if a TCC user does not schedule energy in the day ahead market for transactions consistent with its TCC, it is prevented from using it the next day during the real-time dispatch.

Member Systems explain that CCEM ignores the fact that, when a TCC owner elects not to schedule energy consistent with its TCC in the day-ahead market, another entity's schedule is accepted and the TCC owner receives the congestion revenues. In other words, the TCC is not unused at all. We find that Member Systems' explanation addresses these intervenors' concerns.

Timing of Auction

A number of intervenors state that, for planning purposes, the TCC auction should be held several months before the date the respective TCCs become effective.

We shall not require that the auction be held several months in advance of the TCC effective date. We note that, in order to advance the auction, the ISO would have to conduct its analyses of system capacity earlier as well, making its task more

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97/ Athens Protest at 13-14 (Filed February 6, 1998).

difficult. Also, the auction is but one method for exchanging TCCs and there is no reason that trades in the secondary market cannot be arranged earlier. While we shall not direct a change at this time, we shall direct the ISO to review the issue of auction timing in consultation with the stakeholders. The ISO should report to the Commission within one year on the results of the review and indicate whether changes should be made in auction timing. In this way, the initial TCC auctions will not be delayed, while intervenors will have an opportunity for the ISO to fully consider their concerns.

Information Dissemination

HQ requests the centralization of information on price, availability, and ownership in the auction, secondary, or bilateral market for TCCs. HQ states that lack of information will create inefficiencies in these markets. CCEM also advocates tracking of ownership in the secondary market and posting on OASIS which, according to CCEM, is being done in PJM.

Member Systems contend that CCEM misunderstands the PJM process where TCC transfers in the secondary market are not tracked by the ISO. Member Systems contend that mandating a reporting requirement would be undesirable because it could retard the development of TCC-related financial instruments as well as require the disclosure of information that TCC buyers may view as competitively sensitive. Member Systems contends that CCEM's request "evidences a lack of confidence in "market forces" and concludes that there is no reason that the ISO should operate such a clearinghouse.

We agree that information as to who owns TCCs will aid in the development of a secondary market and will allow the New York ISO and third parties to monitor the TCC market. We shall direct the ISO to establish procedures for the release of this information. Also, we will require that all information regarding TCC bids be kept confidential for six months to help prevent collusive behavior. After a six-month delay, information on individual bids should be released to the public to help interested parties monitor the market.

Hoarding of Grandfathered TCCs

HQ wants the Commission to make sure that grandfathered TCCs are not hoarded by their original holders and that the holders of grandfathered TCCs are not given preferential treatment. HQ feels there is no incentive for holders of TCCs to sell them in secondary markets, and that original holders' ability to choose whether to sell their TCCs either in the secondary market or at auction confers preferential treatment. HQ provides no specific recommendations to address its hoarding concerns. Electric Clearinghouse complains that the initial allocation of grandfathered TCCs and the lack of incentive to sell these instruments will inhibit development of the market and will create a barrier to new entrants.

The hoarding of TCCs is a variation on arguments we have addressed before concerning the hoarding of transmission capacity. We expect that TCC owners will respond to the economic incentives that are created by the TCC market and will not withhold TCCs when it is profitable to release them to the market. As noted above, the ISO will post TCC ownership data. This will provide useful information to parties concerned about hoarding.

TCC Reconfiguration

Currently, it appears that TCCs would be reconfigured only at six-month intervals, corresponding with the TCC lifespan. CCEM argues that this is inflexible because it ignores the possibility that uses and potential constraints vary more often than every six months. CCEM states that if existing TCCs were turned in and the feasibility tests re-run in the middle of a six- month life span, then newer, more valuable TCCs could be issued. CCEM argues that there should be a monthly reconfiguration auction which would aid in eliminating some of the inflexibility of the present proposal. IPPNY also suggests monthly reconfiguration auctions to help promote secondary markets for TCCs.

Member Systems, in principle, agree to such a proposal and offer to explore the idea further with market participants. We shall direct the ISO to include its analysis and recommendations for a reconfiguration auction in the report we have ordered it to make after one year of operation.

Moreover, we agree that the TCC process should be as flexible as possible, and we believe that reconfiguration of TCCs should be an option outside the auction process as well. For example, in order to reconfigure TCCs for a bilateral sale (i.e., to change the points of injection and/or withdrawal), the parties would need the ISO to check if the reconfigured TCC is feasible with other existing TCCs. Reconfiguring TCCs could significantly improve the vitality and robustness of the secondary market. We shall direct the ISO to explore not only a reconfiguration auction, but also a process where any party could request a reconfiguration of its existing TCCs and to include its findings and recommendations in the report due one year after operations begin.

Lifespan of TCCs

A number of intervenors advocate allowing TCCs to have a longer than six-month lifespan, particularly to the extent that TCCs are intended to be the proxy for firm service. 98/ Earlier in this order, we have directed Member Systems to restore the pro forma terms and conditions which will provide the vehicle for obtaining firm services at a fixed price. Customers obtaining long-term firm service will, as a matter of course, be awarded TCCs for use during the term of their commitment. As to residual TCCs -- TCCs that are not associated with an existing physical transmission rights -- we believe that a six-month life-span is reasonable.

Auction Process

CCEM sponsors the testimony of Dr. Robert Wilson, who supports the general format of the TCC auction. 99/ Wilson states that while market power is not an issue in the TCC auction, imperfect information and the lack of incentives to bid into any round of a multi-round auction could potentially lead to strategic behavior and price fluctuations. 100/ Wilson concludes that, contrary to the claims of the Member Systems, the proposed auction structure will not provide adequate price discovery. Wilson argues that the current design of the TCC auction (four rounds for each set of TCCs) does not give any incentive to bidders to allocate bids "proportionately" across the four rounds, or bid in any particular way. Hence, situations could arise in which prices can vary greatly across the rounds due to fluctuations in the demand round by round. This would prevent good price signals to those that wish to bid in future rounds. Wilson suggests an auction with several rounds, but where only the final round's price and transaction are binding. (Thus, unlike the current structure, bids submitted in rounds prior to the final round would not be binding.)

98/ CCEM Protest at 26-28 (Filed February 6, 1998).

99/ CCEM Protest, Testimony of Robert Wilson, Attachment C at 2 (Filed February 6, 1998).

100/ Id. at 6. This claim is made without any proof or concrete example.

Wilson also proposes a simple activity rule here: 101/ A bidder cannot offer a price in a later round that it refused to meet in an earlier round, i.e., a demand bid that is rejected in one round must be increased in the very next round above the previous market price, or else the bid may not be increased above that price in any subsequent round. Thus, a bidder cannot "hold back" its bid in early rounds, let other bidders bid high in the early rounds, and wait until the last round to offer high bids. If the bidder does not meet the market price in one round, it foregoes all later opportunities to meet that price, and thus, to purchase TCCs at that price. In Wilson's view, the rule ensures that market participants will obtain steadily improving information as the auction proceeds about how high they must bid at the close of the auction in order to obtain TCCs. The conclusion reached by Wilson is that this process, over many rounds, will converge to the market clearing price and avoid the price fluctuations he envisions for the current structure.

Finally, CCEM contends that all TCCs should be sold through the auction process rather than as bilateral sales.

We shall reject CCEM's proposal to require all TCC sales to be accomplished through the auction. There is no reason to limit the TCC market to one type of exchange mechanism that is available in order to prevent bilateral sales or other exchange institutions. One of the benefits of TCCs is that they permit parties to transfer transmission rights for short periods and frequently. A standardized, periodic auction process does not permit this.

We shall accept Member Systems' proposed multi-round TCC auction design, with one modification and one clarification described below. An issue of particular concern to the parties has been price discovery, which the multi-round feature of the auction is intended to provide. Wilson's primary concern is that the bidding structure may create incentives not to place properly-valued bids in early rounds. However, the requirement that bids in each round be financially binding should provide incentives for participants to submit bids that reflect their valuation of TCCs. With each progressive round of the auction, participants will obtain more price information based on financially binding bids, which should aid in price discovery. While CCEM's activity rule might also provide such an incentive, we note that auctions for financial transmission rights are untested and we have no compelling reason to determine whether CCEM's proposal would be an improvement.

101/ Id. at 10-12.

We shall therefore initially adopt Member Systems' proposal and direct the ISO to file with the Commission a report after a year that evaluates the experience under the Member Systems' auction mechanism. In addition, the report would propose any changes that it deems necessary in light of experience.

While we generally approve the Member Systems' proposal, we shall require that the ISO (rather than the Transmission Providers) determine the percentage of TCCs to be awarded in each round. This modification would ensure that participants have confidence that the auction is run in a fair and impartial manner.

We shall also require that the ISO not announce in advance of each round what percentage of TCCS will be awarded and what percentage will be carried forward to the next round. We believe that keeping the percentage confidential will reduce the incentive for market participants to bid disproportionately in different rounds. Without advance information about the relative quantities of TCCs to be awarded in any given round, a market participant is more likely to submit proportional bid quantities in each round.

D. Market Based-Rates

Overview of the Proposal

Six Member Systems request authority to sell energy, regulation service, operating reserves, and installed capacity at market-based rates through the ISO-administered market. ConEd's proposal is restricted in that it does not seek authority to sell ancillary services or installed capacity in New York City under market-based rates.

All of these utilities own generation and transmission facilities; however, ConEd, NYSEG and O&R have taken steps to divest significant amounts of generation or announced their intention to do so. For the most part, the decision to divest was made after the application for market-based rates was filed and, therefore, the market analyses do not reflect these divestitures.

The Commission has already authorized market-based rates for bilateral wholesale sales of energy and capacity for the Member Systems. 102/ In some cases, the market-based rate authority is

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102/ Central Hudson Enterprise Corp., et al., 79 FERC ¶61,390
(continued...)

limited to certain regions because the applicant requested limited authority. These market-based rate approvals applied only to sales of energy and capacity, i.e., they did not apply to ancillary services. Also, they did not explicitly authorize market-based rates for sales of energy through the ISO-administered market.

We shall address the requests for energy, ancillary services and installed capacity separately below.

Energy Market

Description

Each of the three largest utilities (Niagara Mohawk, NYSEG, and ConEd) has submitted a separate study examining market power in energy markets. Central Hudson, O&R, and Rochester G&E have simply relied upon the studies they filed in support of their existing market-based rate authority. None of the three new studies of the energy market reflects the Commission's traditional (hub-and-spoke) method. Instead, two of the studies (by Niagara Mohawk and NYSEG) define the geographic market using production models, e.g., Niagara Mohawk uses a PROMOD model to define markets based on the general assumption that the market consists of those entities that can supply energy within 5% of the hourly marginal cost. Inputs to these models reflect a number of assumptions concerning the market: demand and energy forecasts, production costs for each generation plant, estimates of imports from Hydro-Quebec and Ontario Hydro, and estimates of long-term firm bilateral retail and wholesale sales. The third study (by ConEd) defines the market as southeastern New York state, where its generators are located.

102/ (...continued)
(1997); Xenergy, Inc., 79 FERC ¶61,303 (1997); Rochester G&E and ROXDEL, 80 FERC ¶ 61,284 (1997); Orange & Rockland Utilities, Inc. et al., 75 FERC ¶ 61,088 (1996), order on reh'g, 78 FERC ¶ 61,344 (1997); Plum Street Energy Marketing, Inc.,et al., 76 FERC ¶ 61,319 (1996); and Consolidated Edison of New York, Inc., et al. Inc., 78 FERC ¶ 61,298 (1997); 83 FERC ¶ 61,236 (1998). LILCO has never applied for market-based rates and has not joined in this request. LILCO recently sold its transmission system and distribution service area to LIPA. While LILCO retained ownership of some generation, however, it also entered into an agreement to sell power to LIPA. Long Island Lighting Co., 82 FERC ¶ 61,214 (1998), reh'g denied, 83 FERC ¶ 61,076 (1998).

While the three new studies do not define identical geographic markets, they reach similar conclusions, i.e., that there is a significant west to east constraint that divides New York into two separate markets, although New York City and Long Island may often constitute separate markets. Also, while the various models do not adopt the same time periods, use the same data sources or adopt the same assumptions about constraints, all reach similar conclusions regarding market shares and energy market concentration. Specifically, all three studies conclude that Central Hudson, Rochester G&E, and O&R have market shares well below the 20 percent figure the Commission uses as an initial threshold below which it concludes that market power problems are not likely to arise. All three studies also conclude that NYSEG and ConEd each have energy market shares in the relevant markets that are near or below the 20 percent threshold. Finally, all three studies conclude that Niagara Mohawk has energy market shares above the 20 percent level, ranging from 20 to 40 percent in the relevant markets.

The studies also report statistics on market concentration. They indicate that traditional HHIs (based on available economic capacity) are between 2000 and 2500 in the western part of New York, while they are between 1300 and 2100 in the eastern region of the state. 103/ To ameliorate concerns about the high HHI figures, Niagara Mohawk analyzes the profitability of the unilateral exercise of market power. Using its PROMOD model, Niagara Mohawk simulates the effect on its net generation revenues from bidding 10 and 20 percent above variable cost given its current generation ownership and also under a scenario where it restructured its independent power provider (IPP) purchases which currently require Niagara Mohawk to take and pay for power at very high rates. Niagara Mohawk concludes that, without IPP restructuring, it could profitably increase its bids by 10 and 20 percent, although it still loses money. However, once the IPP contracts are restructured, bidding above variable costs is no longer profitable.

The Member Systems also claim that various factors will mitigate their ability to exercise market power: (1) planned divestiture of generating units; (2) Niagara Mohawk's plans to terminate (i.e., divest) a number of purchases as part of its IPP restructuring; (3) retail rate freezes in conjunction with a continuing obligation to sell power to retail native loads; and (4) commitments in retail restructuring proceedings to upgrade

103/ In analyzing mergers, the Department of Justice and the Federal Trade Commission have indicated that HHIs above 1800 may suggest high levels of concentration.

transmission facilities, operate units at cost when necessary to satisfy reliability requirements, and offer power to competitors under standard rates. The Member Systems also conclude that the ISO will be monitoring the market to identify and mitigate market power.

Protests and Commission Response

Defining Energy as a Separate Product

Enron argues that defining energy and capacity as separate products does not permit prices to reflect the true value of reliability. 104/ Enron states that this is because capacity is purchased annually while the market for energy is hourly. Enron would define the relevant product as electricity, not energy and capacity.

We are not troubled by the Member Systems' proposal to define energy sales into the spot market and installed capacity as different products. The Commission has already defined energy and capacity as relevant products, as a general matter. 105/ Moreover, in the context of a power pool, installed capacity is a unique product in that it can be sold without an energy entitlement. 106/

Market Power Conclusions

Although all of the intervenors generally agree that there is a known constraint that often separates New York into an East and West market, they question various aspects of the study analyses. For example, MEUA contends that defining the market in terms of suppliers that can deliver within 5% of the market clearing price overstates supply because 5% is too large to

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104/ Enron Protest, Testimony of Miles O. Bidwell Jr., Appendix 1 at 37-39 (Filed October 31, 1997).

105/ NEPOOL II, 85 FERC at 62,472-83.

106/ For example, when NYSEG sold 1424 MW of generation capacity to AES NY, it entered into an agreement under which NYSEG will receive credit for 1,424 MW of installed capacity under pool rules for up to three years. Under the agreement, while NYSEG rather than AES NY will receive installed capacity credits in the pool, NYSEG will have no entitlement to energy and AES NY will be free to sell the output of the generating unit on the open market.

qualify as a small but significant increase in price. 107/ MEUA also contends that the introduction of LBMP pricing will have the effect of creating even more markets in which the Member Systems have market power. 108/ Enron complains that the studies are based on data that reflect existing levels of demand and price that would not prevail in a competitive environment and cannot serve as proxy for evaluating the Member Systems' ability to exercise market power in competitive markets. With respect to ConEd's application, Enron submits its own analysis to show that for "more than 75 percent of energy supply markets east of Total East market, there are two or fewer competitors who will set the clearing price with their bids." 109/

The intervenors conclude that Member Systems' own study indicates that the markets are concentrated and that the Member Systems' market shares will permit them to exercise market power, thereby defeating their request for market-based rates. 110/ They add that if Member Systems' studies were properly developed, analysis would show even higher market shares.

MEUA contends that there is no need for market-based rates to achieve the benefits of a power exchange which permits all suppliers to receive a market clearing price. MEUA states, for example, that the market clearing price could be based on the marginal cost of the most expensive generating unit dispatched in the hour. 111/ Enron contends that the combination of HHIs and market shares suggests enhanced opportunities for coordinated

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107/ MEUA Protest at 16 (Filed October 31, 1997).

108/ Id. at 17

109/ Enron Protest, Testimony of Richard Tabors, Appendix 2 at 13 (Filed October 31, 1997).

110/ MEUA Protest at 14 (Filed October 31, 1997).

111/ Id. at 18. MEUA contends that, even with cost-based bidding requirements, the Member Systems would be able to exercise market power by strategic bidding and withholding of capacity. MEUA argues that the Commission should not allow a supplier to receive the market clearing price if it owns more than 10% of the generation capacity in a destination market or supplies more than 10% of the fuel for generation in a destination market as a means to minimize the incentive to exercise market power under cost-based rates. These suppliers would be limited to receiving their marginal costs. Id. at 22 action by the various suppliers. Some intervenors contend that the New York market raises a particular concern because the transmission import capability is so limited that more than half of the loads must be met by in-city generation.

Enron also challenges Member Systems' position that the ability to exercise market power will be mitigated by the various commitments made by the Member Systems in retail rate proceedings. Enron also challenges the results of Niagara Mohawk's profitability analysis and complain that the assumptions reflected in the analyses are unclear. Enron also complains that these simulations assume that the Member Systems act independently, not jointly, to raise wholesale prices.

The New York Commission supports market-based rate approval. The New York Commission places great reliance on the profitability analyses and has performed separate analyses which it claims are superior to those provided by the Member Systems. The New York Commission states that the benefit of profitability analyses is that they provide a mechanism to assess the likelihood that market power, even where it exists, can be exercised. The New York Commission’s profitability analyses show that the Member Systems will not be able to profit from the exercise of market power in the near term, primarily because they will be required to serve their franchised retail loads at fixed prices.

The New York Commission also notes that the analyses do not reflect a number of events that have occurred since they were filed or that will occur before market based rates are charged, such as the divestiture of substantial amounts of generation. The New York Commission also explains that, pursuant to a recently negotiated settlement, Niagara Mohawk will restructure its IPP contracts and this should have the same result as divestiture, i.e., releasing generating capacity from Niagara Mohawk's control to the market. The New York Commission concludes that market based rates should be approved, subject to reevaluation after retail access is under way and subject a strong ISO market power monitoring program.

We shall approve market-based rates for energy sales into the spot market. Consistent with our findings in earlier orders approving market-based rate for bilateral transactions, we conclude that each of the six Member Systems lacks market power or will have its market power sufficiently mitigated. While the parties' non-hub-and-spoke analyses, which are intended to evaluate the impact of transmission constraints on market power, indicate that one supplier -- Niagara Mohawk -- may have market shares in the range of 20% to 40%, these analyses do not reflect the significant divestiture of generating assets that is underway in New York, nor the termination of Niagara Mohawk's purchases from IPPs. 112/

Some Member Systems have market shares over 20 percent in many time periods for many products. However, the Commission has not established a 20 percent market share as an absolute, bright-line test. 113/ In fact, since the Commission's traditional analysis of generation dominance considers only market shares based on the seller's annual system peak, our traditional analysis focuses on the single hour of the year when the seller has the least surplus capacity. Implicit in this traditional analysis is the likelihood that, in other hours, market shares are higher than 20 percent as the time-differentiated study submitted by the applicants shows here. Thus, market shares in excess of 20 percent for hours other than the peak hour in the year are not at all unexpected and are not inconsistent with a market share of 20 percent in the peak hour. Our traditional analysis reasonably focuses on such peak periods because it demonstrates the ability of a seller to sustain the exercise of market power. Other factors also suggest that Member Systems are not likely to be able to exercise significant market power and that the ISO will be able to mitigate any market problems that develop. 114/

Also, as noted by the New York Commission, the Member Systems will continue to be required to serve their native load customers at fixed prices during the transition period as a

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112/ NYSEG has entered into contracts to sell over 3,000 MW of coal-fired generating units. ConEd is divesting 5500 MW of capacity. Niagara Mohawk has entered into agreements to sell over 3,500 MW of fossil and hydro capacity, and has negotiated agreements to terminate or restructure as many as 25 of its uneconomic purchase contracts. Central Hudson has agreed to structural separation or divestiture of generation on or before June 30, 2001. O&R recently announced its plans to divest all generation as a condition of its proposed merger with ConEd. Rochester G&E plans to create a separate generating subsidiary that will be regulated by the New York Commission.

113/ See, e.g., USGen Power Services, L.P., 73 FERC ¶ 61,302 at 61,844-45 (1995); Southern Company Services, Inc., 72 FERC ¶ 61,324 at 62,406 (1995), order on reh'g, 74 FERC ¶ 61,141 (1996).

114/ See NEPOOL II, 85 FERC at 62,477.

result of retail rate settlements. Thus, retail customers would be completely insulated from any price increases in the ISO-administered energy market, thereby substantially reducing the incentives of the Member Systems to artificially raise energy prices.

In addition, the existence of suppliers with marginal costs somewhat higher than the market-clearing price will help to discipline the market price. Member Systems' studies did not consider these supplies in its market share analysis because they were assumed not to be in the dispatch. However, the supplies would be available in the event that prices begin to rise above the levels in the computer-simulated dispatch.

Finally, the spot market will be administered by the ISO and supported by a regional transmission tariff. The Member Systems have proposed a plan to monitor the markets for market power and possible market design flaws. We conclude that the monitoring plan, with the modifications that we suggest below, should be adequate to detect market power in the future. To the extent that the ISO's monitoring observes significant exercise of market power, it will be able to take additional steps to mitigate the market power. Together, these factors support our approval of market-based rates for sales into the hourly spot market.

Ancillary Services

Description

Member Systems define regulation service as load following service provided by generation units equipped with automatic generation control (AGC). These are called Class A units. Spinning reserves are operating reserves that can be provided within 10 minutes. All Class A units are required to provide spinning reserves at the ISO's request. Generators not controlled by the ISO through the dispatch (Class B units) may also offer spinning reserves. Non-spinning reserves are classified as 10-minute non-synchronous and 30-minute reserves. The Member Systems provide a single analysis of the generation-based reserves markets in New York.

The analysis methodology is similar to that used for energy. However, it assumes that only New York generators will supply regulation service and spinning reserves and that transmission constraints may affect supply options only with respect to the regulation service market. The Member Systems' analysis shows that, of the utilities seeking market-based rates for ancillary services, four have market shares below 20 percent and two have market shares above 20 percent in at least some markets. Specifically, ConEd has market shares as high as 51 percent, and Niagara Mohawk has market shares as high as 41 percent. Traditional HHIs lie between 2068 and 3520.

Protests and Commission Response

The Member Systems argue that the high market shares indicated in this analysis for some periods and some products are mitigated by the fact that the amount of capacity that is available to provide ancillary services significantly exceeds the demands. In other words, the fact that one supplier other than Con Ed can satisfy the full ancillary reserve requirements independently (and another five suppliers together can fully satisfy demand) prevents ConEd from exercising market power in these markets. With respect to Niagara Mohawk, there are three other suppliers that can independently supply the ancillary services in the west. Member Systems add that the only service where these results do not hold are regulation capacity in the West where four suppliers that can offer 77 MWs; 35 MWs are the estimated requirement. The Member Systems also argue that entry is easy and suggest that Hydro Quebec and many of Niagara Mohawk's soon-to-be restructured IPPs could compete to provide regulation service in the West. The Member Systems also claim that the ISO monitor can easily detect attempts to exercise market power for regulation service by comparing regulation service prices between markets. For all these reasons, the New York utilities argue that market-based rates for regulation service and operating reserve service is justified.

Intervenors state that, while excess capacity may be an important mitigating factor in a market power analysis, it is essentially the whole story for the various categories of ancillary services in New York. The intervenors stress that excess capacity, by itself, is not sufficient to allay market power concerns for several reasons: (1) there may be unexpected extended forced outages; (2) total demand will grow over time reducing any excess capacity; (3) excess capacity can actually intimidate competitive entry; and (4) the largest utilities may have excess capacity in multiple constrained areas and this may affect their market power. Intervenors conclude that the results of the Member Systems' own analysis clearly show that markets are highly concentrated and does not support their request for market-based rates.

We shall approve the Member Systems’ proposal to sell ancillary services under market-based rates. While the market shares for some services are significant, these analyses also do not reflect the divestiture of generating units. Also, the fact that a number of different suppliers are capable of fully satisfying the ISO's needs is an important factor. In all cases, the total potential supply of a particular type of reserve is at least twice the estimated requirement, and sometimes much greater. Differences between supply and demand of this magnitude are likely to deter the exercise of market power, because no individual supplier is irreplaceable. Each supplier -- even one with a 51 percent share of the supply -- can be completely displaced with capacity from other suppliers in light of the substantial differences between total supply and total demand. Also, as we have seen in California, approval of market based rates for energy but not ancillary services can severely distort the markets and affect supply, to the detriment of reliability. 115/ Finally the ISO will be monitoring the markets for market power. In the event that the ISO detects the exercise of market power in these markets, it will have the obligation to report this to the Commission and recommend appropriate steps to mitigate the exercise of market power. This includes taking additional steps that we recommend adding to the proposed monitoring and mitigation plan. Together, these factors support our approval of market-based rates for regulation service and operating reserves.

Installed Capacity

Description

The Member Systems' non-hub-and-spoke analyses for installed capacity yield results that are in line with the results of the hub-and-spoke analyses we have reviewed before. The Member Systems' analysis of installed capacity indicates market shares that are around the 20% threshold that we use as a screen. HHIs are between 1402 and 2093. The Member Systems conclude, based on these findings, that market power is not a concern in the installed capacity market.

Protests and Commission Response

Intervenors focus on the possibility that the ISO may impose locational requirements on installed capacity requirements that would impact the market power of local generation in the same way that physical transmission constraints do.

115/ See AES Redondo Beach, L.L.C. et al., 83 FERC ¶ 61,358, order on reh'g, 85 FERC ¶ 61,123 (1998).

We note that installed capacity is not a new product, i.e., it is the same product for which we have already approved market based rates for each of these Member Systems. While the parties contemplate that a market will be designed to facilitate trading of installed capacity, that would not appear to add market power concerns beyond those that have been satisfied when authority for market-based rates for bilateral trades was granted. However, we shall renew our market-based rate approval for this product in this order. Because the ISO has not yet determined whether and to what extent to impose locational requirements on installed capacity, we are unable to draw conclusions about the impact of such requirements on any suppliers' market power. We note, however, that with respect to the in-city New York market, we have already approved specific market mitigation measures that address this very concern. We shall direct that, in any filing in which the ISO proposes to impose locational requirements on installed capacity, it also address the impacts of that requirement on the markets and propose mitigation measures to the extent necessary.

Monitoring Proposal

Description

No specific monitoring proposal has been tendered. The Member Systems state that, with the support of internal staff and an independent outsider advisor, the ISO will monitor trends and anomalous behavior to determine whether market power is being exercised in any of the markets. They explain that the monitor will also be responsible for identifying and correcting design flaws in market rules and protocols.

They propose that the ISO Board of Directors will oversee the monitoring program and receive and disseminate the advisor's reports to appropriate regulatory authorities. Reports must be made at least annually and the first report is due no later than 15 months from the start of trading. However, the Board may issue additional reports if it judges that conditions warrant it. The ISO and the advisor may suggest changes to market rules and protocols and will establish sanctions that they deem appropriate for violations. However, any changes to the market structure, such as appropriate mitigation measures, must be made by the appropriate regulatory authority, not the monitor.

While no specific monitoring proposal has been tendered for our approval, we have identified some areas that must be addressed when the monitoring program is designed. We note that, with respect to one of the monitor's key functions -- data collection -- the proposal sets limits on what information the monitor can collect and from whom. For example, the Member Systems state that the ISO is prohibited from requiring generators to report specific cost information since it could be commercially sensitive.

Protests and Commission Response

The interventions do not focus on the monitoring proposal, although Enron states that the Member Systems should not be able to suggest how their own potential to exercise market power should be monitored.

We agree that there should be an ISO monitoring program that should identify both market power and market design flaws. As we have noted in previous ISO orders, 116/ both market power and market design flaws have the potential to interfere with the full benefits of a newly-formed ISO. By monitoring for both, the New York ISO can quickly identify potential impediments to an efficient market and take steps approved by the Commission to remedy problems.

The monitoring proposal is presented as a general plan and, therefore, our comments will be general pending the filing of and our approval of the ISO's specific monitoring plan. In this regard, we find it reasonable to rely on an outside independent advisor to flesh out the details. We believe that relying on both internal staff and an outside expert will help to provide the expertise and the independence necessary for a successful monitoring program. However, it is important to develop a detailed plan promptly, since our approval of market-based pricing authority depends, in part, on adequate monitoring. It is also important that the internal staff and outside expert have adequate resources. Therefore, we direct the ISO to file a detailed monitoring plan (including the staffing and other resources devoted to monitoring) within six months of this order or the date the ISO commences operations, whichever is sooner. We also direct the ISO to consider whether it is sufficient to rely on a single outside advisor rather than a committee of independent advisors.

In developing the detailed plan, we offer two observations. First, the proposal submitted here indicates that the ISO would look for market anomalies as part of the process of monitoring

116/ See Pacific Gas & Electric Co., et al., 77 FERC ¶ 61,265 (1996); PJM, 81 FERC ¶ 61,257 (1997); NEPOOL II, 85 FERC at 62,479.

for market power. We agree that market anomalies can provide an important indication of market problems, but they may not tell the whole story. For example, the Member Systems suggest that the monitor might easily detect the exercise of market power for regulation service in the West by comparing prices in the West with prices in the East (where they expect greater competition). The East is the market with most of the load and the constraints, so one might expect competitive prices in the East to exceed prices in the West virtually at all times. This would be true even if market power is being exercised in the West. Thus, simply observing that prices in the West are less than those in the East does not necessarily indicate a lack of market power.

Second, the monitoring program should look not only for traditional ways of exercising market power, such as withholding capacity, but also other ways that may be unique to the transmission network. For example, because of the complexities of the grid and the relationship between the generation-based services, utilities might find it profitable to underbid high cost generation in some areas of the grid in order to create transmission constraints that would confer or enhance market power of other generators in other areas.

Also, the Commission will have to balance the need for the ISO to collect market data with concerns regarding commercial sensitivity of such data, and we will do so at the time we act on the ISO's detailed proposed plan. The current proposal limits the ISO's ability to collect commercially sensitive data (such as cost data from generators), but it is precisely such data that might indicate whether a unit with market power would have the incentive to use it. When the ISO files its proposed plan, it should address these issues. It is possible that commercially sensitive information could remain confidential for some period of time to resolve other market participants' concerns.

Finally, the monitor should be allowed to target its monitoring efforts, thereby more intensively monitor generators with certain characteristics that are more likely to be associated with the exercise of market power (such as high market shares). There is no reason why monitoring should be uniformly applied to all generators, as opportunities to exercise market power are not uniformly distributed throughout the market.

Mitigation Measures

Description

The Member Systems' proposal contains no details regarding mitigation remedies that the ISO could implement in the event that market power is detected through its monitoring. It proposes to develop those details after it selects an outside advisor.

Protests and Commission Response

MEUA recommends two mitigation remedies for sellers detected with market power. The first is to allow the ISO to cap the bids of the seller at its applicable marginal cost. MEUA argues that this cap merely forces the seller to bid in the same way as a competitive firm. (Since the cap would apply to the seller’s bid but not its price, the seller could receive the applicable market-clearing price, even if the price exceeds the seller’s bid.) The second remedy is to allow the ISO to require such a seller to bid all generation capacity not committed to produce energy in other transactions into the ISO-administered markets. MEUA argues that these two requirements would assure that the seller does not withhold capacity in order to exercise market power.

Again our comments are necessarily general because, other than the localized market mitigation measures already approved for New York City, we have not been presented with a specific proposal to mitigate any market power that the ISO may detect once operations begin. MEUA has proposed two market mitigation measures: (1) a marginal cost bidding cap that would cap a seller’s bid at the level that would be expected from a seller behaving competitively; and (2) the obligation to bid all spare capacity into the ISO-administered markets. We note that the Commission has adopted similar provisions for the New England ISO. Therefore, we shall direct the ISO to address MEUA's proposal in formulating the market monitoring and mitigation plan that it will file.

Other Market Power Issues

MEUA contends that the Commission should not approve market-based rates because the Member Systems' proposed ISO Tariff does not satisfy the requirements of Order No. 888 and, therefore, will not mitigate their market power. Clearinghouse expresses similar concerns. Our directions in this order for changes to the New York ISO Tariff that will ensure comparable, open access to all transmission users moots the intervenors' concerns in this regard.

Sithe contends that, to the extent that the Member Systems recover stranded costs from retail loads, they will have a subsidy that will allow them to bid below cost without harm, thereby creating a barrier to entry. Sithe contends that the Commission expressed a concern in our California ISO orders that, in such circumstances, suppliers could engage in predatory pricing. Sithe's concerns, while valid, are premature. Member Systems intend to revise the ISO proposal to implement retail access. As we did with respect to the California proposal, we shall require a clarification that the retail access program approved by the New York Commission "would not compensate for financial losses resulting from operating generators at energy prices below incremental costs." 117/

The Commission Orders:

(A) The motions to intervene out-of-time in this proceeding are hereby granted, as discussed in the body of this order.

(B) The answers in this proceeding are hereby accepted for filing, as discussed in the body of this order.

(C) The New York Independent System Operator Tariff is hereby conditionally accepted for filing, to become effective the date the ISO commences operation, subject to the revisions discussed in the body of this order.

(D) The requests of the applicants for market-based rates for energy, ancillary services and installed capacity sold through the markets administered by the New York ISO are hereby accepted, subject to the conditions discussed in the body of this order.

(E) Member Systems are hereby directed to file revised tariff sheets that reflect the requirements of this order within 90 days of the date of this order.

(F) Member Systems are hereby directed to file a transmission tariff that is separate from the rate schedules that govern non-transmission functions, within 90 days of the date of this order.

(G) Member Systems are hereby directed to make a single filing to amend the intra-Member Systems' agreements, as

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117/ Pacific Gas & Electric Co., et al., 77 FERC ¶ 61,265 at 62,093 (1996).

discussed in the body of this order, within 90 days of the date of this order.

(H) The New York ISO is hereby directed to file service agreements for the Member Systems,, as discussed in the body of this order, within 30 days from the date the ISO commences operation.

(I) The Member Systems are hereby directed to provide further justification, or revise their proposal regarding the criteria under which an installed capacity requirement might apply to LSEs, within 90 days of the date of this order, as discussed in the body of this order.

(J) The New York ISO is hereby directed to file a plan for the installation of metering equipment, as discussed in the body of this order, within one year from the date of this order.

(K) The New York ISO is hereby directed to submit, within 15 months of operation, a report on the first twelve months of operation, to include: (1) an evaluation of the ancillary service markets; (2) an analysis of the method and possible options in dealing with storm watch conditions; (3) an evaluation of the use of external suppliers of ancillary services; (4) its analysis and recommendations for both a reconfiguration auction and a process where parties could request a reconfiguration of its existing TCCs; and (5) an evaluation of the auction mechanism and any proposed changes thereto, as discussed in the body of this order.

(L) The New York ISO, after consultation with the stakeholders, is hereby directed to submit a report after six months from the commencement of operations on the feasibility and cost of transmission bidding.

(M) The New York ISO is hereby directed to release information regarding energy, ancillary services and TCC bids to the public after a six-month delay, as discussed in the body of this order.

(N) The New York ISO is hereby directed to file a detailed monitoring and mitigation plan, as discussed in the body of this order, within six months of the date of this order or the date that the ISO commences operations, whichever comes sooner.

(O) The Member Systems are hereby directed to submit specific details regarding the release of TCCs associated with Native Load at the time they file to revise the tariff to implement retail transmission services.

(P) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held concerning the justness and reasonableness of: (a) the divisor used to develop the hourly charge for the New York ISO Tariff; and (b) formulas used to compute the Transmission Service Charge; (c) the methodology used to compute marginal losses and the information made available to customers to allow informed decision making (d) the criteria used to accredit generation as meeting the installed capacity requirement.

(Q) A presiding administrative law judge, to be designated by the Chief Administrative Law Judge, shall convene a conference to be held within approximately fifteen (15) days after the issuance of this order, in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E. Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, including a date for the submission of Member Systems' case-in-chief, and to rule on all motions (except motions to dismiss) as provided for in the Commission's Rules of Practice and Procedure.

(R) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held on the dispute concerning MEUA's services under the Member Systems' individual open access tariffs, as discussed in the body of this order.

(S) The hearing ordered in Ordering Paragraph (R) above shall be held in abeyance pending settlement discussions between the parties pursuant to Ordering Paragraph (U) below. The hearing shall remain in abeyance until the Chief Administrative Law Judge determines that the settlement judge procedures should be terminated and the hearing should go forward.

(T) A presiding administrative law judge, to be designated by the Chief Administrative Law Judge, shall convene a conference in this proceeding, to be held within approximately fifteen (15) days after the Chief Judge determines as a consequence of the reports of the settlement judge required under rule 603(g)(2) and consultation with the settlement judge under Rule 603(h), 18 C.F.R. § 385.603(g)(2), (h) (1998), that the hearing ordered in Ordering Paragraph (R) above should go forward, in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

(U) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (1998), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within approximately fifteen (15) days of the date if the issuance of this order. To the extent consistent with this order, the designated settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene an initial settlement conference as soon as practicable.

By the Commission.

(S E A L)

David P. Boergers,
Secretary.

Appendix A

Motions To Intervene and Notices of Intervention
in Docket No. ER97-4234-000

Aquila Power Corp. *

Athens Generating Company

CalEnergy Company, Inc.

City of Oswego, New York

Coalition for a Competitive Electric Market

Cogen Technologies Linden Venture, LP

Constellation Power Source

Consumers Energy Company

Coral Power, LLC *

Edison Electric Institute

Electric Clearinghouse, Inc.

Electric Power Supply Association

Energetix, Inc. *

Energy Marketers Coalition *

Engage Energy US, L.P.

Hydro-Québec

Indeck Energy Services, Inc.

Independent Power Producers of New York

LG&E Power, Inc.

Long Island Power Authority

Multiple Intervenors

Municipal Electric Utilities Association of New York State

New York City Department of Law

New York Public Service Commission

New York State Consumer Protection Board

New York State Department of Economic Development

Northeast Utilities Service Company

NYPA Industrial Intervenors

Plum Street Energy Marketing, Inc. *

Project for Sustainable FERC Energy Policy

Public Service Electric and Gas Company

SEF Power Corp. *

Selkirk Cogen Partners, L.P. *

Sithe/Independence Power Partners, L.P.

Starrett City, Inc. *

Suffolk County Electrical Agency

U.S. Generating Company

US Gen Power Services, L.P.

Williams Energy Services Company

* Motion to intervene out-of-time.