UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Central Hudson Gas & Electric Corporation	)		
Consolidated Edison Company of New York, Inc.	)		
Long Island Lighting Company	)	Docket Nos.	ER97-1523-000
New York State Electric & Gas Corporation	)		OA97-470-000, and
Niagara Mohawk Power Corporation	)		ER97-4234-000
Orange and Rockland Utilities, Inc.	)		(not consolidated)
Rochester Gas and Electric Corporation	)		
Power Authority of the State of New York	)		
New York Power Pool	)		

Affidavit of Susan L. Pope

12 December 1997

Affidavit of Susan L. Pope, Ph.D.,[1] On Congestion Pricing Under the Proposal To Restructure the New York State Electricity Market

Susan L. Pope, being duly sworn, deposes and says:

INTRODUCTION

The eight members of the New York Power Pool (Transmission Providers) are proposing to the Federal Energy Regulatory Commission (Commission) a restructured wholesale electricity market for the State of New York (Transmission Providers' Proposal).[2] The proposal calls for the creation of a new market structure; new institutions and governance arrangements; open access to the statewide transmission system; and new pricing rules for both energy and transmission. A distinguishing feature of the proposed pricing rules is congestion cost pricing, similar to the pricing rules proposed by the Supporting Companies of the PJM Interconnection that were recently approved by the Commission.[3]

The purpose of my affidavit is to provide information to the Commission relating to the implementation of the Transmission Providers' proposal for congestion cost pricing. In Appendix A to a March 28, 1997, letter to the PJM Interconnection, the Commission Staff posed twenty-five questions about congestion cost pricing. These are shown in Exhibit 1 to my affidavit. My affidavit replies to these questions as though they had been asked with regard to the New York

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1 Susan L. Pope is a Principal at Putnam, Hayes & Bartlett, Inc., in Cambridge, Massachusetts. She has been a consultant on electric market reform and transmission issues to the New York State Transmission Providers for over four years. She has also been a consultant on similar issues for the Supporting Companies of the PJM Interconnection and San Diego Gas & Electric Corporation. The author holds an A.B. in applied mathematics and a M.A. and Ph.D. in business economics from Harvard University.

2 The Transmission Providers are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., 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 the Power Authority of the State of New York.

3 *Pennsylvania – New Jersey – Maryland Interconnection, et al.*, "Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreement, Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control over Jurisdictional Facilities, and Denying Rehearings," 81 FERC ¶61,257 (1997).

Transmission Providers' Proposal. This information is intended to assist the Commission in evaluating the congestion cost pricing system proposed in New York.

SUMMARY

In the Appendix A data request the Commission Staff focused on practical questions about how congestion cost pricing and fixed transmission rights (FTRs), which in New York are called transmission congestion contracts (TCCs), will work from the perspective of market participants. My responses to their questions address, in the context of the Transmission Providers' Proposal, such key issues as how the congestion charges[4] that are paid by transmission customers are calculated, how transmission customers can manage their congestion costs, how TCCs will be allocated and how TCCs can be used to provide the financial equivalent of firm transmission.

My responses to the Commission Staff's questions explain that:

- All congestion charges will be determined from the energy prices that result from the ISO-facilitated LBMP market.[5] Under the Transmission Providers' Proposal these are called locational-based marginal prices (LBMPs).
- Under the New York Transmission Providers' Proposal customers undertaking bilateral transactions and customers buying energy from the ISO-facilitated LBMP market will pay the same congestion charges.[6]
- Customers may lock in their congestion-related costs before undertaking transactions by purchasing TCCs. The holder of a TCC will be paid congestion rents that will offset the transmission congestion charge incurred for a one

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4 In the ISO Tariff, the congestion charges paid by transmission customers are called Congestion Rents.

5 The term "ISO-facilitated LBMP market" refers to the day-ahead and real-time bid-based spot markets for energy and transmission that are facilitated by the ISO and in which all buying and selling occur based on locational-based marginal prices.

6 As described in the response to question A5, customers with transmission agreements existing as of January 31, 1997 (the date of the Transmission Providers' first ISO Tariff filing) that do not convert their rights under these agreements into TCCs are excepted from paying congestion charges. These customers do not receive congestion rents and also do not pay congestion charges for the portion of their bilateral transaction that is covered by their rights. The net amount that they pay to transmit power under a bilateral transaction is the same, however, as that paid by a customer that converts its grandfathered rights to TCCs. While the customer that converts to TCCs explicitly pays congestion charges, the ISO pays these charges back to it as congestion rents.

megawatt bilateral transaction scheduled between the points of injection and withdrawal stated in the TCC. TCCs provide the financial equivalent of firm transmission because a customer can lock in its congestion-related costs in advance at the price it pays to purchase TCCs. Customers with grandfathered transmission rights that convert their rights to TCCs lock in their congestion-related costs at the price they pay under their current transmission contract.

- Customers that are scheduling bilateral transactions may choose to take non-firm transmission service under the ISO Tariff. If a customer chooses non-firm service, its bilateral transaction will be reduced or terminated in lieu of incurring congestion charges.

- The ISO-facilitated LBMP market will also provide customers with several ways to manage the LBMPs that they pay or receive (including congestion charges). Customers may manage these LBMPs through the bids that they make into the Day-Ahead[7] and Real-Time Markets. They may also monitor and respond to the pricing information that is made available after the completion of each Day-Ahead Market and after each hour of the Real-Time Market. Customers that schedule transactions a day ahead pay day-ahead prices and are not exposed to real-time changes in LBMPs and congestion charges.

- The ISO will pay bus-specific LBMPs to generators selling into the ISO-facilitated market. In contrast, it will initially charge zonal LBMPs to load-serving entities (LSEs) that buy from the ISO-facilitated market, due to software and metering limitations.

- There are several steps in the initial allocation of TCCs. The ISO Tariff proposes an initial allocation of TCCs (or Grandfathered Rights) to customers receiving service under transmission contracts in existence as of as of January 31, 1997 and an allocation of TCCs to Transmission Providers to serve their native load from specified remote energy sources. The ISO will then allocate Residual TCCs to the Transmission Providers, which they are required to sell

7 Capitalized terms are being used as specifically defined in the ISO Tariff.

either over the OASIS or in the centralized TCC auction. The ISO will run a centralized TCC auction to sell TCCs based on any remaining transmission capacity as well as any transmission capacity associated with TCCs that are released for sale in the auction.

- After the initial allocation of TCCs, the ISO will periodically allocate new TCCs by holding a centralized TCC auction. The TCCs sold in this auction will be based on transmission capacity made available by the expiration of the TCCs sold in the previous auction, by the expiration of grandfathered transmission contracts and by TCC holders that have released TCCs for sale in the auction, either voluntarily or by mandate. After the initial allocation of TCCs the Transmission Providers may sell their initial allocations over the OASIS, as well as through the centralized TCC auction. All other TCCs may be sold over the OASIS, through the TCC auction or on the secondary market.

- The ISO and the auctioneer will use power flow modeling to verify the simultaneous feasibility of the set of TCCs that is allocated for the transmission system. The feasibility test ensures that when the transmission system is operating under normal conditions the congestion charges the ISO collects will be sufficient to pay congestion rents to all TCC holders.

- The ISO Tariff will fully fund TCCs, which means that TCC holders will always be paid all of the congestion rents that they are owed. If the ISO collects insufficient congestion revenue during some hours of a month (because the transmission system is not operating under normal conditions), the shortfall will be funded from excess congestion revenues that the ISO collects during other hours of the month; any remainder will be distributed among the Transmission Providers and collected through their individual Transmission Service Charges (TSCs).[8]

8 In the case of the Power Authority of the State of New York (NYPA), the shortfall will be included in the NYPA Transmission Adjustment Charge (NTAC).

- A market participant that finances a grid expansion will receive a portfolio of point-to-point TCCs that are associated with the increase in the transfer capability of the transmission system. These TCCs will be allocated to the market participant for the life of the new transmission asset.

Exhibit 2 to my affidavit is an accounting example that shows how LBMPs are used to pay generators that sell into the ISO-facilitated LBMP market, to charge LSEs that buy from the ISO-facilitated LBMP market and to calculate the transmission usage charge (TUC) for bilateral transmission customers. It also shows the calculation of the congestion rents that the ISO pays to holders of TCCs and how TCCs can be used to provide the financial equivalent of firm transmission.

RESPONSES TO THE COMMISSION STAFF'S APPENDIX A QUESTIONS

In the discussion below, each question that the Commission Staff posed to PJM in Appendix A is restated, as necessary, in terms appropriate for New York and then answered.

A1. Describe the models used to develop energy prices (LBMPs). Explain how they are related. Also explain how the output from one model feeds into the other.

Please see the accompanying affidavits by Dr. A. Mayer Sasson, Dr. Walter A. Pfuntner and Mr. Steven L. Corey. Dr. Sasson describes the software systems that will be used by the New York ISO, including the software that will be used to develop LBMPs. LBMPs will be calculated from the output of the security-constrained unit commitment and security-constrained economic dispatch models that the ISO will use to manage the operation of the transmission system and to coordinate the wholesale energy market. In the Day-Ahead Market, LBMPs will be calculated from the output of the security-constrained unit commitment model that the ISO will run based on day-ahead bids from market participants. Similarly, real-time LBMPs will be calculated from the output of the security-constrained dispatch model that the ISO will run based on hourly bids from market participants. Dr. Pfuntner and Mr. Corey describe how the data used to calculate LBMPs in the Day-Ahead and Real-Time Markets are provided by the security-constrained unit commitment and security-constrained dispatch models, respectively. These data are provided to software that calculates LBMPs using the equation shown in Attachment I to the ISO Tariff.

A2. Provide a detailed description of the information that will be required in submitting a bid. If a standard format for submitting bid information will be required, describe the format and provide an example.

The tables in Attachment E to the ISO Tariff provide a detailed description of the information that will be required in submitting a bid. A standard format for submitting bid information is being tested as part of the bid/post software system discussed in Dr. Sasson's testimony.

A3. Explain whether, in any given hour, a buyer (LSE) and seller (generator) located at the same bus face the same energy price (LBMP). If they do not face the same LBMP, explain the basis for the difference.

Under the proposed ISO Tariff each generator selling energy into the ISO-facilitated LBMP market will be paid the LBMP at its bus because the data needed to calculate bus-specific LBMPs for generators is provided by the existing software and generators have real-time metering.[9] Bus-specific LBMPs will provide an economically efficient price signal to generators, as described in Professor William W. Hogan's affidavit accompanying the January 31 Filing.[10]

However, there are currently impediments to charging LSE's bus-specific LBMPs. There is not sufficient real-time load metering to determine load at each bus in real time. Moreover, existing software reflects existing load-metering capabilities and hence does not provide the data needed to calculate LBMPs at all load buses. Consequently, the Transmission Providers are initially proposing to use zonal LBMPs to charge most buyers for their purchases from the ISO-facilitated LBMP market.[11] Each zonal LBMP will be a weighted average of the LBMPs at load buses within the zone, where the weights are based on a predetermined distribution of load to load buses in that zone.[12] See Attachment I to the ISO Tariff.

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9 Note that while all generators at a bus face the same LBMP, some generators committed by the ISO may receive supplemental payments if their LBMP revenue is less than their bid cost, as described in Section 4.36 of the ISO Tariff. The supplemental payments mean that two generators at the same bus may receive different total payments from the ISO for the same level of production.

10 "Report on the Proposal to Restructure the New York Electricity Market," William W. Hogan, January 31, 1997, pp. 39, 40 and 42 (henceforth referred to as "January Hogan Affidavit").

11 Buyers with revenue-quality real-time meters who interconnect with the transmission system at a bus where LBMPs are currently calculated will be charged the LBMP at that bus, subject to individual Transmission Provider settlements. Also, buyers located outside the New York control area will be charged a bus-specific LBMP that is the same as the energy price that will be received by a seller at their bus.

12 Due to short-term software limitations, the zonal LBMPs may initially have to be calculated as a weighted average of the LBMPs at generator buses in the zone, .

Even though generators will be paid bus-specific LBMPs and LSEs will be charged zonal LBMPs, there will be little difference between LBMPs faced by buyers and sellers at the same bus in hours in which LBMPs do not differ substantially among buses within a zone.[13] Moreover, as wholesale customers become equipped with revenue-quality real-time energy meters and are interconnected to the transmission system, the software can be modified to calculate LBMPs at additional load buses, so that the customers will be able to be billed based on bus-specific LBMPs.

A4. Explain whether congestion charges will be determined differently for network customers and for point-to-point customers.

Under the Transmission Providers' Proposal, there are no network and point-to-point service classifications.[14] All congestion (and loss) charges will be location-specific and will be determined on a flow basis. This means that the congestion (and loss) charges paid by all customers will depend on the effect of their transactions on energy flows across constrained transmission facilities and, hence, on the costs incurred due to out-of-merit dispatch.

Both firm and non-firm transmission service for bilateral transactions will be available under the ISO Tariff, or customers may buy energy directly from the ISO-facilitated LBMP market. Customers can obtain firm service for a bilateral transaction by committing to pay a TUC that includes a charge for congestion and losses. A firm transaction will be scheduled even if the transmission system becomes congested. Alternatively, a customer can choose non-firm transmission service by agreeing to pay for marginal losses but not congestion charges, in which

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13 Note that LBMPs may differ between buses within a zone even when there is no active transmission constraint within the zone. The examples in Appendix A of the January Hogan Affidavit show that congestion costs may differ between two buses even when there is no constrained transmission facility directly linking the buses. This is because in an interconnected transmission system, transactions at the two buses have different effects on energy flows across transmission constraints that are occurring elsewhere in the system. LBMPs will also differ between buses within a zone because of differences in marginal losses.

14 However, the ISO Tariff has characteristics of both network and point-to-point service. Under the Transmission Providers' Proposal, there are two basic types of charges for transmission usage: the TUC and the TSC. The service obtained by paying the TUC is similar to point-to-point service, while the service obtained by paying the TSC is similar to network service. That is, payment of the TUC is for service between two specific locations, like pro forma point-to-point service. However, such service cannot be reserved for more than a day in advance, so there is no firm point-to-point service that can be obtained by paying only the TUC--a TCC would be required in addition. Likewise, payment of the TSC is for service between any points on the New York grid and is based on the customer's load, which are characteristics similar to pro forma network service.

case its bilateral transaction will be curtailed when there is congestion. See response to Question A8.

Under the proposed system, customers will pay the same congestion and loss charges whether they buy energy from the ISO-facilitated LBMP market or pay a TUC for a firm bilateral transaction. Specifically, customers will pay congestion and loss charges based on LBMPs, as follows:

- Customers buying energy from the ISO-facilitated LBMP market pay the congestion and loss charges as a component of the zonal LBMP that applies at their bus. The zonal LBMP is a weighted average of the LBMPs at buses within their withdrawal zone. The LBMP at a bus includes a charge for the marginal price of energy at the reference bus, a charge for losses that is the marginal cost of losses relative to the reference bus (the loss component) and a congestion charge that is the marginal cost of congestion relative to the reference bus (the congestion component).[15] Therefore, the congestion charge for customers buying from the ISO-facilitated LBMP market is a weighted average of the congestion components of the LBMPs at the buses within their withdrawal zone.[16] See response to Question A3 and Attachment I to the ISO Tariff.

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15 The reference bus proposed in the ISO Tariff is the Marcy 345 kV bus near Utica. Under the proposed system, the marginal cost of losses and marginal cost of congestion are defined to be zero at the reference bus, and the costs of congestion and losses at all other buses are then measured relative to this bus. The choice of a reference bus does not affect the LBMPs for the system; it is primarily needed to separate out the congestion and loss components of the LBMPs.

16 Analytically, the LBMP, γ_i, and zonal LBMP, γ_i^Z, at bus i can be expressed as follows:

$$\text{LBMP}_i = \gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C \qquad \text{(Equation 1)}$$

$$\gamma_i^Z = \lambda^R + \gamma_i^{L,Z} + \gamma_i^{C,Z}. \qquad \text{(Equation 2)}$$

where: λ^R = the marginal price of energy at the reference bus;
γ_i^L = the marginal cost of losses at bus i relative to the reference bus;
γ_i^C = the marginal cost of congestion at bus i relative to the reference bus;
$\gamma_i^{L,Z}$ = the marginal cost of losses in bus i's zone, relative to the reference bus; and
$\gamma_i^{C,Z}$ = the marginal cost of congestion in bus i's zone, relative to the reference bus.

This notation will be used in subsequent footnotes. See Attachment I to the ISO Tariff.

- Customers undertaking firm bilateral transactions will pay the congestion and loss charges as components of the TUC.[17] The TUC for each megawatthour of a firm bilateral transaction is equal to the zonal LBMP at the point of withdrawal minus the LBMP at the point of injection. The TUC contains charges for both the marginal cost of congestion and losses, since the two LBMPs that the TUC is calculated from have both congestion and loss components. The congestion component of the TUC is equal to the congestion component of the zonal LBMP at the point of withdrawal for the transaction minus the congestion component of the LBMP at the point of injection. Similarly, the loss component of the TUC is equal to the loss component of the zonal LBMP at the point of withdrawal for the transaction minus the loss component of the LBMP at the point of injection. See Section 4.19 of the ISO Tariff.[18]

The equivalence between the congestion and loss charges paid by customers undertaking firm bilateral transactions and customers buying energy from the ISO-facilitated LBMP market can be seen by adding the cost of the bilaterally negotiated energy purchase to the TUC paid by the bilateral transmission customer. The total price that the bilateral customer pays for delivered energy is equal to: a TUC consisting of the zonal LBMP at the point of withdrawal minus the LBMP at the point of injection of the bilateral generator, plus the bilaterally negotiated energy purchase price. The difference between the bilaterally negotiated energy purchase price and the LBMP at the point of injection for the generator serving the bilateral contract is the amount by which the bilateral price paid for energy is over or under the market price at the generator's location (LBMP). Therefore, the total price that the bilateral customer pays for delivered energy is the zonal LBMP at its point of withdrawal, adjusted for the above- or below-market value of its bilaterally negotiated energy contract.[19] For example, if the bilateral energy price equals the

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17 Accounting and billing exceptions for bilateral transmission customers with Grandfathered Rights are described in response to Question A5.

18 If the withdrawal is from location i and the injection is at location j, then a firm bilateral transmission customer would pay:

$$\text{TUC per MWh from j to i} = \gamma_i^{Z} - \gamma_j = (\gamma_i^{L,Z} - \gamma_j^{L}) + (\gamma_i^{C,Z} - \gamma_j^{C}). \qquad \text{(Equation 3)}$$

Equations 1 and 2 have been substituted for γ_i^Z and γ_j in this expression for the TUC.

19 Adding the cost of the bilateral energy purchase at bus j, X, to Equation 3 provides an expression for the total price for delivered energy paid by the bilateral customer:

$$\text{TUC and Energy Charge per MWh} = \gamma_i^{Z} - \gamma_j + X. \qquad \text{(Equation 4)}$$

injection point.[24] The congestion rent payment received for a TCC will offset the transmission congestion charge incurred for a 1 MW bilateral transaction scheduled a day ahead between the points of injection and withdrawal stated in the TCC.[25] The congestion rent for the TCC will offset the congestion charge for the 1 MW transaction, no matter what the congestion charge turns out to be. To the extent that a customer owns TCCs, the congestion component of the TUC will have no effect on the costs it incurs to complete a bilateral transaction scheduled a day ahead. TCCs provide the financial equivalent of firm transmission because a customer can lock in its congestion-related costs far in advance at the cost of purchasing a TCC, just as the purchaser of firm transmission under the current system can lock in its transmission costs far in advance for the cost of entering into a transmission agreement. Customers with grandfathered transmission rights that convert their rights to TCCs lock in their congestion-related costs at the price they pay under their current transmission contract. See response to Question A22.

While TCCs provide a mechanism for customers to hedge themselves against fluctuations in the congestion component of the TUC, TCCs only hedge congestion charges. The loss component of the TUC (which is equal to the loss component of the zonal LBMP at the withdrawal bus, minus the loss component of the LBMP at the injection bus, multiplied by the number of megawatts transmitted) cannot be hedged by TCCs.

ISO Scheduling and Dispatch Process

All participants, even those who do not have TCCs, can use the ISO scheduling and dispatch process to manage the impact of congestion on the LBMPs they pay or receive.[26] Congestion affects the LBMPs received by generators selling into the ISO-facilitated LBMP market, the zonal LBMPs paid by LSEs buying from the LBMP market and the TUC paid by firm bilateral transmission customers. Section 4 of the ISO Tariff specifies scheduling and operating

24 The congestion rents that the ISO pays to TCC holders are based on congestion charges that it collects in the Day-Ahead Market. See response to Question A20.

25 A TCC may not exactly offset the transmission congestion charge for a 1 MW bilateral transaction scheduled after the Day-Ahead Market. This is because the congestion rents paid to a TCC holder are based on day-ahead LBMPs, while the congestion charge for a transaction scheduled after the Day-Ahead Market is based on real-time LBMPs.

26 An LSE may also manage its congestion charges by purchasing energy under a delivered-price bilateral energy contract at its location(s).

procedures for the Day-Ahead and Real-Time Markets[27] through which customers can gain information about expected and actual LBMPs, TUCs and congestion charges, and can adjust their schedules and actual production and consumption. While the bidding and scheduling procedures will not allow customers to know their congestion-related costs in advance of the dispatch, as do TCCs, bids will allow customers to prespecify how they would like to change their day-ahead schedules, or actual production or consumption, in response to how congestion is affecting their LBMPs.

Day-Ahead Market

A summary of the bidding and scheduling procedures for the Day-Ahead Market follows:

- Generators who wish to sell energy into the ISO-facilitated LBMP market provide day-ahead incremental bids. These incremental bids indicate the minimum price at which each generator is willing to be scheduled to produce and sell each megawatthour of energy above its minimum generation level.

- LSEs may provide an energy bid into the Day-Ahead Market in order to cap the LBMP that they pay for load scheduled day ahead. If the zonal LBMP is above an LSE's bid, some or all of the LSE's load would not be scheduled in the Day-Ahead Market and would not be charged the day-ahead zonal LBMP.[28] Due to short-term software limitations, the dispatch software initially will not be able to accommodate bids from load or to calculate LBMPs at specific load buses. The lack of real-time metering could also limit the use of bids by price-dispatchable loads during the initial implementation of the LBMP system.

- Customers undertaking firm bilateral transactions will provide their day-ahead transmission schedules, if any, to the ISO. They must also provide a decremental bid (or bids) for each generator serving the bilateral contract (or

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27 Together, these two markets are called the two-settlement system.

28 The LSE load that is not scheduled in the Day-Ahead Market would either be interrupted in real time, met with a bilateral transaction that the LSE schedules 90 minutes before the dispatch hour or served out of the real-time ISO-facilitated LBMP market.

accept the ISO's default bid)[29] and may provide price-dispatchable bids for their load, subject to the limitations mentioned above. If the LBMP falls below a bilateral generator's decremental bid, the bilateral customer is indicating that it wishes to purchase the energy necessary to serve its bilateral transaction from the Day-Ahead Market. Similarly, some or all of the load would not be scheduled in the Day-Ahead Market if the day-ahead zonal LBMP exceeded its load bid.[30]

The spread between a firm bilateral customer's generator and load bids will allow it to manage the net TUC (including the congestion charge) that it pays to complete a transaction in which its bilateral load is served by its bilateral generator.[31] Due to software limitations, bilateral transmission customers cannot directly bid a TUC that they are willing to pay to complete transactions. However, as will be discussed in the response to Question A8, bilateral transaction customers will have the option of choosing non-firm service, which allows them to elect to be curtailed in lieu of paying congestion charges.

The bidding and scheduling procedures for the Day-Ahead Market provide customers with several ways to manage their LBMPs and TUCs. First, all customers, including those undertaking firm bilateral transactions, may be scheduled based on bids that they provide into the Day-Ahead Market. The use of bids will allow an LSE to limit the LBMP that it is scheduled to pay, will allow a generator to put a floor on the LBMP that it is paid for producing energy and will allow a firm bilateral transmission customer to manage its TUC.

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29 Generators serving bilateral transactions that have Grandfathered Rights will not be required to provide decremental bids. If they do not, their schedule will be reduced only after the schedules of all generators with incremental or decremental bids have been reduced. Any other bilateral generators that do not wish to have their output reduced for whatever reason may make very low (possibly even negative) decremental bids.

30 Like LSE load, any bilateral load within New York that is not scheduled in the Day-Ahead Market would either be interrupted in real time or would pay real-time congestion charges through either a TUC or the zonal LBMP.

31 A transmission-only transaction occurs only to the extent that the bilateral generator is injecting energy to serve the bilateral load. Therefore, the maximum TUC that a bilateral transmission customer will pay, in net terms, to complete a transaction from its bilateral generator to its load is limited by the spread between its load and generator bids.

Second, once LSEs, generators and bilateral transactions are scheduled a day ahead, they have locked in the LBMP or TUC for their schedule. They will not be exposed to fluctuations in LBMPs and TUCs that may occur during the dispatch day unless their actual transactions are different than their schedule. Since, by design, all market participants are scheduled based on the economic preferences indicated by their bids, the LBMPs and TUCs that they lock in a day ahead (and the congestion component of the LBMPs) will be charges that they are willing to pay (or receive). Customers with firm bilateral transactions can lock in not only the congestion component of the TUC, but the entire TUC (congestion and losses) for all transactions that are scheduled a day ahead.

Finally, the Day-Ahead Market will provide all customers with a forecast of LBMPs and congestion charges that they can use to make informed decisions about their hour-to-hour use of the system to complete transactions that they did not schedule a day ahead, or to change their day-ahead schedules, subject to the appropriate settlement in the Real-Time Market. The day-ahead LBMPs will be posted once the schedule for the following operating day has been determined. By examining day-ahead LBMPs, all market participants will know what expectations the market has formed concerning LBMPs. These expectations should provide a forecast of the LBMPs that will actually prevail in the real-time dispatch, because customers will exploit any disequilibrium between the day-ahead and real-time prices.[32]

Real-Time Market

Market participants, including those undertaking firm bilateral transactions, may provide bids into the Real-Time Market and will be dispatched based on those bids.[33] Therefore, just as in the Day-Ahead Market, the use of bids will allow an LSE to limit the LBMP that it pays, will allow a

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32 If day-ahead LBMPs were systematically lower than real-time LBMPs, fewer generators would bid energy into the day-ahead dispatch, preferring to be dispatched up during the hour so that they receive the real-time LBMPs. As generators withdrew from the Day-Ahead Market, the day-ahead LBMPs would tend to rise to equilibrate with the real-time LBMPs. Alternatively, if day-ahead LBMPs were systematically higher than real-time LBMPs, fewer LSEs would schedule their purchases of energy a day ahead, preferring to wait and pay the real-time LBMPs. As LSEs withdrew from the Day-Ahead Market, the day-ahead LBMPs would tend to fall until they were in equilibrium with the real-time LBMPs. Consequently, the day-ahead LBMP for a given hour at a given location should, on average, be approximately equal to the real-time LBMP observed for that hour at that location.

33 An LSE must demonstrate that it is dispatchable within the time constraints of the hourly market in order to be permitted to provide an energy bid into the real-time dispatch.

generator to specify a floor on the LBMP it is paid for producing energy and will allow a firm bilateral transmission customer to manage its TUC. In addition, customers will be able to observe the hourly LBMPs and congestion charges resulting from the Real-Time Market. As they refine their expectations of what real-time LBMPs will prevail later in the day, they may adjust their bids and schedules for later hours.

A8. Explain whether non-firm customers can indicate in advance a threshold price for the congestion charge that they are willing to pay, and above which they would be willing to be curtailed.

There are two classes of transmission service under the ISO Tariff, firm and non-firm. With firm transmission service, customers with bilateral transactions may provide bids separately for the generator and load involved in the transaction; however, they cannot directly bid a threshold price for their congestion charge. Non-firm transmission service, on the other hand, allows a customer to indicate that it would like its bilateral transaction to be curtailed whenever it would otherwise incur a congestion charge. The threshold price for the congestion charge for non-firm transmission is zero. See responses to Questions A4 and A7.

Non-firm transactions can be requested during either the Day-Ahead Market or the ISO's Balancing Market Evaluation (BME), which occurs 90 minutes before the dispatch hour, and will be accepted if the ISO estimates that the real-time congestion charge component of the TUC will be zero (or less) for the transaction. In the real-time dispatch there is a small chance that a congestion charge could appear during one of the five-minute intervals of the security-constrained dispatch in which a non-firm bilateral transaction has been scheduled. If and when this occurs, the non-firm transaction would incur a congestion charge for that interval. The non-firm transaction would then be terminated for the remainder of the hour and would not incur any additional congestion charges during that hour. If a non-firm bilateral transaction is terminated, the bilateral generator and LSE would have the option of selling or buying energy in the ISO-facilitated LBMP market, making alternative bilateral arrangements or ceasing to generate or consume. Non-firm transactions scheduled in the Day-Ahead Market will not be financial commitments; that is, they will pay real-time LBMPs for their full transaction, not only for deviations from their day-ahead schedule. Non-firm service will be offered for transactions wholly within New York as well as those between New York and neighboring control areas (wheeling into, out of or through New York). See Attachment E to the ISO Tariff.

Even though non-firm transmission service allows customers to bid a threshold price of zero for congestion, LSEs supplying end-users located in New York State will still generally pay a congestion charge to serve their loads. Any LSE load that is associated with a non-firm bilateral transaction that is not scheduled, or that is terminated in real time, would be served out of the real-time ISO-facilitated LBMP market unless the load is interrupted in real time. If the load is supplied from the LBMP market, the LSE would be charged the zonal LBMP, which includes congestion charges. Once the requisite software, metering and controls are in place, customers will be able to specify prices above which they wish to interrupt their consumption of power (i.e., they will be able to bid price-dispatchable demand), which will permit them to avoid congestion charges altogether by interrupting their consumption.

A9. Explain whether it is possible for a transaction to contribute to congestion and yet not be subject to a congestion charge.

Any bilateral transaction between load and generation within or across the borders of the New York control area that contributes to congestion will be subject to a congestion charge, except for transactions using Grandfathered Rights as discussed in the response to Question A5. In addition, as discussed in the response to Question A6, transactions occurring outside the New York control area may cause unscheduled loop flow within New York, but will not incur a congestion charge because the parties involved in the transaction are not subject to the ISO Tariff and there is currently no system available to charge for such flows.

A10. Explain how TCCs will initially be allocated by the New York ISO.

The initial allocation of TCCs occurs in four steps, as described in the ISO Tariff:

1. Grandfathered TCCs or Grandfathered Rights will be allocated to customers that have grandfathered transmission contracts.

2. Transmission Providers will receive Native Load TCCs based on their use of the transmission system to serve native load from specified distant energy sources.

3. The ISO will allocate Residual TCCs to the Transmission Providers based on the transmission system's remaining transfer capability. As part of the initial

allocation process, the Transmission Providers are required to sell their Residual TCCs either over the OASIS or through the centralized TCC auction.

4. The ISO will sell TCCs in a centralized auction. The centralized auction will serve several purposes in the initial allocation. First, it will make transmission capacity available for sale that has not been allocated as Grandfathered TCCs, Grandfathered Rights, Native Load TCCs or Residual TCCs.[34] Second, it will provide a centralized process for selling Residual TCCs that the Transmission Providers do not sell over the OASIS. Finally, it provides a forum for the release, reconfiguration and sale of the transfer capability associated with any TCC.

In each of these steps, which are described in detail below, TCCs will be allocated separately for the summer and winter capability periods and for peak and off-peak hours. All TCCs will be defined from point to point, from a specific injection bus to a specific load bus.[35] See Attachments G and M to the ISO Tariff.

Allocation of Grandfathered TCCs or Grandfathered Rights

The first step in the allocation process for TCCs is to assign Grandfathered TCCs or Grandfathered Rights to customers with transmission contracts that existed as of January 31, 1997. The ISO Tariff provides for grandfathered transmission rights associated with most transmission contracts between the Transmission Providers, as well as all transmission contracts between the Transmission Providers and third parties. Each customer under a grandfathered contract will have the choice of either retaining its existing transmission rights (Grandfathered

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34 In this affidavit, the term Residual TCCs is used to refer *only* to TCCs allocated to the Transmission Providers before the TCC auction. As discussed later in this response, these Residual TCCs are unlikely to exhaust the system's entire transfer capability. The ISO Tariff also uses the term Residual TCCs to refer to TCCs sold in the TCC auction that are based on any transmission capacity that is not allocated as Grandfathered Rights, Grandfathered TCCs or Native Load TCCs.

35 Points of injection are generally expected to be generation buses, while points of withdrawal will generally be load buses. In the initial allocation of TCCs, a point of injection or withdrawal may be a zone rather than a bus; if so, a set of distribution factors will be used to assign a portfolio of point-to-point TCCs to or from a set of buses within that zone.

Rights) or of converting its rights into TCCs (Grandfathered TCCs).[36] Grandfathered TCCs will correspond to the transmission rights they replace, so that a customer that currently owns the right to transmit 100 MW of power from Bus A to Bus B would be able to convert it into 100 TCCs from Bus A to Bus B. Attachment G to the ISO Tariff contains the details of the grandfathering proposal, and Attachment H to the ISO Tariff includes a table that shows the grandfathering treatment of each transmission contract that existed on January 31, 1997, the date of the Transmission Providers' first ISO Tariff filing.

Allocation of Native Load TCCs

The second step in the initial allocation of TCCs is to assign Native Load TCCs (also included as part of Grandfathered TCCs) to the Transmission Providers based on their reservations to serve their native load from specified remote energy sources. Native Load TCCs are associated with transmission capacity used by a Transmission Provider to serve its native load from a distant generating unit that it owns or from a supplier with which it has a power supply contract. Native Load TCCs are allocated when the Transmission Providers' right to this transmission is not covered by an explicit transmission contract. The Transmission Providers will receive TCCs to cover their native load uses of the transmission system, and will not have the option of obtaining Grandfathered Rights. Native Load TCCs will be released in conjunction with each Transmission Provider's retail access program, that is, these TCCs will either be sold over the OASIS, sold through the TCC auction or directly assigned to loads. Attachment H of the ISO Tariff includes a table that shows the proposed assignment of Native Load TCCs.

The Native Load TCCs that are proposed in the ISO Tariff will be subject to a test of simultaneous feasibility. If necessary, the proposed Native Load TCCs will be proportionately reduced until all Grandfathered TCCs and Grandfathered Rights are simultaneously feasible. See responses to Questions A14 and A15 for a discussion of simultaneous feasibility.

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36 Third party transmission customers also have the option of canceling their transmission contract based on its current terms, in which case they would no longer pay the contract rate and would not receive Grandfathered TCCs or Grandfathered Rights.

Allocation of Residual TCCs

The ISO will allocate Residual TCCs to the Transmission Providers based on the transfer capability that remains after the assignment of Grandfathered Rights and Grandfathered TCCs (including Native Load TCCs). The Residual TCCs that are initially allocated to the Transmission Providers will expire at the end of the LBMP Transition Period; that is, five years after the implementation of the two-settlement system. As each centralized TCC auction approaches, the Transmission Providers are required to sell their Residual TCCs for the auction period either over the OASIS or through the centralized TCC auction.

Residual TCCs will be allocated based on operating study power flows that are routinely solved for the summer and winter capability periods. The power flows serve as the basis for identifying Residual TCCs that can be feasibly assigned after taking into account the transfer capability claimed by Grandfathered TCCs and Grandfathered Rights. In brief, the ISO will allocate Residual TCCs as follows:

- It will estimate the residual capacity that remains across each interface[37] by calculating the flows across the interface that occur in the operating study power flows and subtracting the flows across the interface that are attributable to Grandfathered TCCs and Grandfathered Rights.
- It will allocate the TCCs associated with the residual capacity on each interface among the Transmission Providers. This allocation will be based on each Transmission Providers' MW-Mile coefficient for an interface, which is a measure of the proportion of the residual energy flows across an interface that occur on the Transmission Providers' transmission lines. See Attachment K to the ISO Tariff.

This process for allocating Residual TCCs may not exhaust all of the point-to-point TCCs that can be defined for the transmission system because it allocates TCCs only across a predefined set of interfaces and is based on predefined operating studies that may not describe

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37 See the tables in Attachment H to the ISO Tariff for a list of defined interfaces.

the maximum transfer of power on the New York system. Any transmission capacity not allocated as Residual TCCs will be made available for sale in the centralized TCC auction.

Centralized TCC Auction

The following discussion provides an overview of the centralized TCC auction, which is the final step in the initial allocation of TCCs. The technical and commercial aspects of the TCC auction are described in detail in the affidavit of Professor William W. Hogan that accompanies this filing and in Attachment M to the ISO Tariff.

The ISO and the auctioneer will run a centralized TCC auction to sell TCCs for the first summer or winter capability period following the implementation of the ISO Tariff.[38] The TCC auction will be conducted in several rounds, with TCCs and money changing hands after each round. Any party that meets the creditworthiness criteria that are established by the ISO may bid to purchase TCCs in any round of the auction. Winning bidders in each round will receive TCCs and will pay the ISO the market-clearing price for the TCCs in that round.

The TCCs that are offered for sale in the initial centralized TCC auction will be based on transmission capacity from several sources:

- Transmission capacity that is not initially allocated as Grandfathered TCCs, Grandfathered Rights or Residual TCCs.[39]
- Transmission capacity associated with Residual TCCs that the Transmission Providers have not sold over the OASIS for the initial capability period.
- Transmission capacity from TCCs that are voluntarily released for sale in the auction. Any Primary Owner of a Grandfathered TCC may choose to sell its TCC through the auction as may qualified parties that have purchased TCCs on the OASIS. Some Transmission Providers may choose to sell their Native

38 The auctioneer will generally have responsibility for the commercial aspects of the TCC auction. In particular, it will work with the ISO to run the power flows for the initial auctions and will later assume full responsibility for the power flows.

39 The Capacity Benefit Margin and Transmission Reliability Margin will be accounted for in the auction through a reduction in the transfer limits that constrain the TCCs that can feasibly be sold.

Load TCCs in the centralized TCC auction as they release them under their retail access programs.

During each of the initial rounds of the auction, a share of this transmission capacity will be sold as TCCs; these initial rounds are referred to as Stage 1 of the auction. For example, if there were ten Stage 1 rounds, 10 percent of this capacity could be sold in each round. The rounds in Stage 2 of the auction provide a further opportunity for TCC holders, including any party that purchased TCCs during Stage 1, to resell its TCC through the centralized auction and a further opportunity for any buyer to bid to buy a TCC. As described in Section IV of Professor William W. Hogan's accompanying affidavit, if a TCC is released for resale into any round of the auction, the transfer capability associated with the TCC may be reconfigured and sold as part of one or more other TCCs.

The objective of each round of the auction will be to award TCCs that maximize the value of the TCCs sold in that round (as measured by the winning bids). The winning bids in each round of the auction will be determined using a power flow model since all TCCs, including those allocated in the auction and those allocated before the auction, must be simultaneously feasible. This simultaneous feasibility test and the assumptions under which the power flow analysis will be conducted are described in more detail in the response to Question A14.

A11. Are TCCs path-specific? Provide a list of the TCCs that will be allocated.

Neither TCCs nor any other charges or payments proposed under the ISO Tariff are path-specific. A TCC is defined between two physical points, a point of injection and a point of withdrawal, and the holder is paid the difference between the congestion components of the LBMPs that apply at these points without regard to the path that energy may actually take in moving between them.

As described in the response to Question A10, there are several steps in the allocation of TCCs. The ISO Tariff proposes an initial allocation of TCCs to customers with existing transmission contracts (Grandfathered TCCs) and for native load uses of the transmission system (Native Load TCCs). Attachment M to the ISO Tariff describes the processes for allocating Residual TCCs and for conducting the centralized TCC auction, but not the actual allocation resulting from these processes.

The Grandfathered TCCs and Native Load TCCs are shown in Tables 1 and 3 of Attachment H to the ISO Tariff. The tables show the point of injection for the TCC (column labeled "from"), the point of withdrawal (column labeled "to"), the number of TCCs (summer and winter) and the transmission interfaces that the TCC crosses. Each TCC is defined point-to-point and will be paid congestion rents between its points of injection and withdrawal. The direct assignment of Native Load TCCs in Table 3 of Attachment H is subject to modification based on the results of a test of the simultaneous feasibility of all of the TCCs and Grandfathered Rights listed in Tables 1 and 3. See responses to Questions A10 and A14.

It should be noted that the interface allocations in Tables 1, 3 and 4 of Attachment H are included only to provide information about the proportion of the New York transmission system capacity that will be claimed by existing transmission agreements. The interface allocations are shown on a contract-path basis for closed interfaces,[40] so that they may only roughly indicate the number of additional TCCs that can be awarded between two points based on a simultaneously feasible power flow. Moreover, since parties with TCCs may not actually undertake transactions that correspond to their TCCs, the interface allocations are unlikely to be indicative of whether or not a transaction between two points will be feasible in a particular hour. TCCs are not rights to interfaces; they are rights (or obligations) to receive (or pay) congestion rents.

A12. Explain whether there will be any charge to acquire TCCs.

The charge paid to acquire TCCs will depend on how the TCCs are obtained:

- A Transmission Provider or third party that receives Grandfathered TCCs based on an existing transmission contract will pay the charges specified in the contract.[41] The charge to a Transmission Provider cannot be changed until the end of the LBMP Transition Period, that is, five years after the implementation of the two-settlement system. After the LBMP Transition Period, this charge

40 This means that the interface allocation for each TCC is determined under the assumption that either all or none of the power flow that would result from a bilateral transaction corresponding to the TCC would cross the interface.

41 The current contract terms may need to be adjusted to exclude losses, since the charge for losses will be unbundled under the ISO Tariff.

may be updated, if permitted under the terms and conditions of the contract. See Attachment G to the ISO Tariff.

- Transmission Providers that receive Native Load TCCs will not pay an explicit charge for them, since the cost of the transmission capacity supporting these TCCs is already included in their revenue requirement. With the exception of NYPA, the Transmission Providers will receive these TCCs on behalf of all of their load, which is paying for this transmission cost of service through either the TSC, the charge under an existing transmission agreement or a bundled transmission rate. The congestion rents attributable to Native Load TCCs (or the revenue from selling these TCCs) will be deducted from each Transmission Provider's transmission cost of service or, in the case of NYPA, from the NTAC. See Attachment C to the ISO Tariff for the NTAC formula.

- Transmission Providers that receive Residual TCCs will not pay an explicit charge for them. The Transmission Providers receive these TCCs as part of the process for allocating their individual claims to the value of residual transmission capacity, that is, capacity that is not claimed by Grandfathered Rights and Grandfathered TCCs (including Native Load TCCs). Since the Transmission Providers are obligated to sell their Residual TCCs, the assignment of Residual TCCs is essentially a method for allocating revenues from TCC sales. With the exception of NYPA, the Transmission Providers receive this allocation on behalf of all of their load, which is paying for the transmission cost of service through either the TSC, the charge under an existing transmission agreement or a bundled transmission rate. The revenue from the sale of Residual TCCs will be deducted from each Transmission Provider's transmission cost of service or, in the case of NYPA, from the NTAC.

- Customers that buy TCCs in any round of the centralized TCC auction will pay the market-clearing price for the TCCs determined in that round. This payment is described in detail in Professor William W. Hogan's affidavit on the TCC auction that accompanies this filing. See also Attachment M to the ISO Tariff.

- Customers that buy TCCs over the OASIS will pay the price negotiated over the OASIS for the TCCs.

- Customers that buy TCCs in a private secondary market sale will pay the price that has been negotiated for the transaction.

A13. Show how the TCCs would be allocated if they tracked current transmission use entitlements by virtue of ownership or contract. To the extent you indicate a contractual right, identify the rate schedule which governs the transmission entitlement. Explain whether the initial allocation of TCCs could reflect something other than the current usage rights.

The responses to Questions A10 and A11 explain the relationship between the allocation of TCCs and existing transmission use entitlements. In general, the Transmission Providers have honored existing contracts and transmission entitlements, including use of the transmission system to serve native load, in developing this allocation. Table 1 in Attachment H to the ISO Tariff identifies the FERC rate schedules that govern all existing transmission agreements.

A14. Explain how the New York ISO will determine whether a given set of TCCs can feasibly be distributed.

The ISO will evaluate the feasibility of TCCs during three steps in the TCC allocation process that is described in the response to Question A10: In allocating Native Load TCCs, in allocating Residual TCCs and in conducting a centralized TCC auction. The feasibility test ensures that when the transmission system is operating under normal conditions the congestion charges the ISO collects will be sufficient to pay congestion rents to all TCC holders.

A set of TCCs is feasible if injections and withdrawals corresponding to each TCC could simultaneously be accommodated on the transmission system without causing security violations. A feasible allocation of TCCs means that, if the ISO were to run a power flow model that included energy injections and withdrawals at the points of injection and withdrawal of each and every megawatt of TCCs and Grandfathered Rights, the model would produce an energy dispatch that would not violate any security limit used in the security-constrained dispatch.[42]

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42 An intuitive explanation for this feasibility test is that all customers with TCCs should simultaneously be able to use their TCCs to schedule a corresponding bilateral transaction. If it would be feasible for all holders of TCCs (and Grandfathered Rights) to undertake the bilateral transactions corresponding to their TCCs (and Grandfathered

The ISO will run power flow analyses to evaluate the feasibility of Native Load TCCs and Residual TCCs. It will also initially work with the auctioneer to conduct power flow analyses to evaluate the feasibility of the TCCs that are sold in the centralized TCC auction.

- The ISO will evaluate whether the proposed Native Load TCCs are feasible, given the allocation of Grandfathered TCCs and Grandfathered Rights based on existing agreements. As discussed in the response to Question A10, if these TCCs and Grandfathered Rights are not simultaneously feasible, the Native Load TCCs will be proportionately reduced.

- The ISO will estimate and allocate Residual TCCs based on a seasonal Operating Study Power Flow, as described in response to Question A10. A solved power flow will be the basis for deciding what Residual TCCs may feasibly be allocated over and above the Grandfathered TCCs and Grandfathered Rights.

- The ISO and auctioneer will conduct each round of the TCC auction using an optimal power flow (OPF) model (or a similar power flow model). TCCs and Grandfathered Rights that are not released for sale into the auction will be loaded into the power flow model as fixed injections and withdrawals, in order to reserve the associated transmission capacity throughout the auction. TCCs will be awarded subject to the constraint that all Grandfathered Rights and TCCs, including those sold in the auction, are simultaneously feasible in the security-constrained power flow.

In each case the power flow models that the ISO (or auctioneer) will use will ensure that the TCCs will be feasible when the transmission system is operating under normal conditions. Among other things, the power flow models will:

- Reflect operating conditions for a specific summer or winter capability period.

Rights) simultaneously, the ISO would collect sufficient congestion rents to provide the financial equivalent of firm transmission.

- Include the same representation of transmission contingencies and constraints that is used in the real-time system dispatch.[43]
- Assume that all transmission facilities are in service, except as modeled in the transmission contingencies.
- Include assumptions concerning the operation of the transmission system external to New York that come from a NERC seasonal operating study base case, which includes an estimate of parallel flow based on known contract transfers plus anticipated transactions that typically occur on the system. This base case representation of external transactions provides the loop flow assumptions for the power flow models.

A15. Explain how the New York ISO can ensure that all of the TCCs and Grandfathered Rights can always be feasibly supported by the grid at every moment in time.

As described in the response to the previous question, the feasibility test for TCCs and Grandfathered Rights ensures that the ISO will collect sufficient congestion revenues to pay congestion rents to all holders of TCCs when the transmission system is operating under normal conditions. This test has nothing to do with whether or not the actual operation of the transmission system is feasible or secure at any moment in time. Whether or not the TCCs and Grandfathered Rights can or cannot feasibly be supported on the grid at any point in time will have no impact on system reliability or continuity of service.

The response to Question A14 describes the methods that the ISO will use to determine whether an initial allocation of TCCs is simultaneously feasible. The ISO will base its evaluation on a set of reasonable assumptions, with the result that the TCCs should be feasible during all security-constrained dispatches except those in which there is a transmission outage or an unusually high level of uncompensated loop flow during a time when the transmission system is constrained. The method for allocating TCCs reasonably balances the inevitable conflict between the quantity of transmission rights that are allocated for the transmission system and the possibility that the rights may be infeasible under some circumstances. This issue must be faced

43 The Capacity Benefit Margin and Transmission Reliability Margin will be reflected in a reduction in the transfer limits for relevant transmission constraints.

by any system of transmission rights, including the contract-path transmission rights in use today, and is not unique to TCCs.

A16. Address the possibility that the total TCCs and Grandfathered Rights that are allocated cannot feasibly be supported by the grid and explain how the requests of individual customers will be modified or curtailed.

Either a transmission outage or an unusually high level of uncompensated loop flow during a time in which the transmission system is constrained could mean that the TCCs and Grandfathered Rights are not feasible in a given hour. When they are not simultaneously feasible, the ISO may not collect sufficient congestion revenue to pay congestion rents to all TCC holders. The revenue inadequacy occurs because the ISO collects less congestion rents from scheduling generation at locations with low LBMPs to serve loads at locations with high LBMPs, but its obligation to TCC holders does not decrease.[44]

The ISO Tariff contains a proposal to fully fund TCCs so that holders of TCCs and Grandfathered Rights will not be directly affected when the ISO collects insufficient congestion revenue. Full funding means that TCC holders will be paid all of the congestion rents they are owed, even if the ISO collects insufficient congestion revenues in a given hour. Grandfathered Rights holders will also be able to use all of the megawatts of their rights in the hour without paying a congestion charge (except if the injections and withdrawals corresponding to the use of those rights would imperil system security). Any shortfall in the congestion rents that the ISO collects from the operation of the LBMP market during an hour of the Day-Ahead Market will be funded from excess congestion revenues that the ISO collects during other hours of the month.[45] In the event that there are insufficient excess congestion revenues to fund all of the day-ahead congestion revenue shortfall that occurs during the month, the shortfall will be distributed among

44 The congestion rents that the ISO pays to TCC holders are based on day-ahead LBMPs and the congestion charges that the ISO collects day ahead. Therefore, any shortfall in congestion revenue will be the result of transmission outages or loop flow that are included in the ISO's dispatch of the Day-Ahead Market.

45 Excess congestion revenues can arise when the transfer capability on the system exceeds the total quantity of TCCs and Grandfathered Rights in existence at the time. For example, they can arise if different constraints bind in the dispatch than were binding in the final TCC auction load flow, or if loop flow is less than anticipated in the TCC auction load flow. Excess congestion revenues will also be collected by the ISO if owners of Grandfathered Rights do not use their rights during a congestion dispatch, since they are not entitled to receive congestion rents instead.

the Transmission Providers using the Interface MW-Mile Methodology and will be included in each Transmission Provider's TSC (NTAC, in the case of NYPA).[46]

The ownership of TCCs will in no way determine priority for use of the transmission system during system contingencies. The ISO will determine the actual usage of the transmission system based on bids provided by generators, LSEs and customers with bilateral transactions. If the transfer capability changes as a result of transmission outages or parallel flows, the ISO will schedule use of the system a day ahead and will dispatch the system (redispatching when necessary) as necessary in real time in order to maintain reliability. Under normal conditions, any redispatch of the system to accommodate transmission outages will be based on bids.[47] However, the ISO will also have a set of procedures for curtailing transactions and/or load so as to maintain system reliability when warranted by events on the transmission system. See Section 2.6 of Attachment E to ISO Tariff.

A17. Once TCCs are initially allocated, explain how new TCCs will be allocated.

After the initial allocation of TCCs, the ISO and the auctioneer will run a centralized TCC auction every six months, in which they will sell new TCCs for a particular summer or winter capability period. The ISO Tariff proposes that the centralized auction will be run every six months because of its newness and perceived risk; however, this periodicity may be changed by the ISO in recognition of the commercial needs of market participants. The accompanying affidavit by Professor William W. Hogan describes the centralized TCC auction in detail.

The TCCs that are offered for sale in each centralized TCC auction will be based on transmission capacity from several sources:

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46 Note that while the full funding proposal will increase the amounts paid to each TCC holder (relative to the amounts they would have been paid if TCC payments had been curtailed in some way), the amounts that buyers pay for TCCs should also increase. Any increase in the total TSC-related revenue requirement (for all Transmission Providers) that results from fully funding TCCs will be at least partially offset by an increase in the TSC revenue credit from the sale of TCCs.

47 Generators serving bilateral transactions that have Grandfathered Rights will not be required to provide decremental bids. If they do not, the schedule will be reduced only after the schedules of all generators with incremental or decremental bids have been reduced.

- Transmission capacity that is not initially allocated as Residual TCCs, Grandfathered TCCs or Grandfathered Rights.[48]

- Transmission capacity associated with Residual TCCs that the Transmission Providers have not sold over the OASIS for the current capability period.

- Transmission capacity associated with transmission agreements that expire.

- Transmission capacity associated with TCCs that have been voluntarily offered for sale in the centralized auction. Any Primary Owner of a Grandfathered TCC may choose to sell its TCC through the auction as may qualified parties that have purchased TCCs on the OASIS. Voluntary sales could include TCCs that are released in conjunction with the Transmission Providers' retail access programs.

In short, the new TCCs sold in the centralized auction will be based on all transmission capacity that is not retained as Grandfathered TCCs (including Native Load TCCs), Residual TCCs or Grandfathered Rights. At the conclusion of each six month capability period (or whatever other period the ISO designates), the TCCs sold in the preceding auction will expire and new TCCs will be sold. The TCCs sold in the TCC auction will be subject to the test of simultaneous feasibility described in the response to Question 14.

Wholly apart from the sale of TCCs through the periodic TCC auction, the Transmission Providers may sell their initial allocations of Grandfathered TCCs, Native Load TCC and Residual TCCs over the OASIS. For the first year of ISO operation, the term of these sales will be limited to six months. Market participants (including the Transmission Providers) may buy and sell other existing TCCs either over the OASIS or in a secondary market at whatever value they may place on them.

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48 The Capacity Benefit Margin and Transmission Reliability Margin will be included in the auction through a reduction in the transfer limits that constrain the TCCs that can feasibly be sold.

A18. Explain how the allocation of new TCCs will affect existing TCCs.

The allocation of new TCCs by the ISO and the auctioneer in each centralized TCC auction will not affect the Grandfathered TCCs (including Native Load TCCs) and Residual TCCs that have already been allocated, whether or not they have been sold by their original owner. The allocation of new TCCs in the centralized TCC auction must be simultaneously feasible along with any TCCs and Grandfathered Rights that have been previously allocated. The ISO Tariff also proposes to fully fund TCCs so that TCC holders will be paid the full amount of the congestion rents that they are owed, even when there is an occurrence on the transmission system that reduces the congestion revenue collected by the ISO. Because of the feasibility test and full funding, the allocation of new TCCs will have no effect on payments made to the holders of existing TCCs.

A19. Explain how TCCs for expansions to the grid would be distributed.

In general, the ISO Tariff anticipates that most transmission expansions will take place at the initiative and expense of market participants, although actual construction and/or operation of the new facilities may be carried out by the Transmission Providers. In return, the market participant paying for an expansion would receive TCCs for the life of the new transmission asset. These TCCs would provide it with the financial equivalent of firm transmission service even if, in spite of the expansion, the grid were to become congested.

The TCCs that would be allocated for the transmission expansion would correspond to the incremental transmission capacity made available over and above existing TCCs. These incremental TCCs would not necessarily be equal to the rated capacity of the expansion. Rather, the incremental TCCs made available by the expansion would be evaluated on a flow basis. It is likely that in many cases a portfolio of different TCCs would be allocated, since a single expansion could increase transfer capability between more than just two points on the grid. Alternatively, if the expansion reduced the grid's ability to support some existing TCCs, the party undertaking the expansion would be required to hold "negative" TCCs as part of this portfolio in order to compensate existing TCC holders. For example, if an existing A to B TCC were infeasible after the expansion, the party undertaking the expansion would be required to hold a TCC from B to A. These are called negative TCCs because the value of their congestion rents is generally expected to be negative, entailing a payment obligation to the ISO.

In future TCC auctions, the TCCs assigned for a transmission expansion would be treated like Grandfathered TCCs. They could either be released and sold in the centralized TCC auction or the owner could hold them out of the auction, in which case the associated transmission capacity would be reserved in the power flow model used to run the auction.

A20. Explain how revenue that the ISO collects from congestion charges will be distributed to TCC holders. Explain whether TCC holders could take actions that would change the paths for which they hold TCCs from unconstrained to constrained paths.

The congestion rents that the ISO pays to TCC holders will come from the congestion charges that it collects in operating the Day-Ahead Market. See response to Question A4.[49] Under most circumstances, the ISO should collect at least enough congestion revenue in each hour of the Day-Ahead Market to pay each TCC holder congestion rents that are equal to the difference in the congestion cost components of the day-ahead LBMPs that apply at the points of injection and withdrawal for the TCC.[50] In hours in which the ISO collects insufficient congestion revenue the shortfall will be funded from excess congestion revenues and, if necessary, from the Transmission Providers' TSCs (and the NTAC), as described in the response to Question A16. In hours in which the ISO collects extra congestion revenue, the extra revenue will be first used to fund congestion revenue shortfalls during other hours of the month and then any remainder will be allocated to the Transmission Providers. The investor-owned Transmission Providers will use it as an offset against their TSCs, while NYPA will use it as an offset against the NTAC, as will be described in the response to Question A21.

TCCs are not associated with transmission paths. Rather, TCCs are associated with pairs of injection and withdrawal points and will hedge the difference in the congestion components of the LBMPs at these points without regard to whether there are one or more transmission "paths" between the points. For this reason, TCC holders cannot "take actions that would change the

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49 The reason TCC holders are paid based on congestion revenue collected in the Day-Ahead Market is that in a two-settlement system (i.e., a system with a Day-Ahead Market and day-ahead financial commitments, as well as a Real-Time Market), day-ahead financial commitments are a full set of claims on the use of the transmission system in real time, and on the associated real-time congestion revenue. In a two-settlement system, the real-time congestion revenue is not used to pay TCC holders. Rather, the congestion revenue used to pay TCC holders is based on the congestion charges collected for the day-ahead financial commitments.

50 Using the notation developed in the answer to Question A4, the holder of a TCC from bus j to bus i would be paid $\gamma_i^{C,Z} - \gamma_j^{C}$.

paths for which they hold TCCs from unconstrained to constrained paths," since they would not hold TCCs for particular paths. Moreover, the injection and withdrawal locations for each TCC will be fixed. TCC holders cannot change these locations from hour to hour in order to increase their congestion rent collections.

A21. Explain the method for distributing "excess congestion revenues."

Excess congestion revenues occur when the ISO collects congestion charges in an hour of the Day-Ahead Market that exceed the congestion rents that it owes to TCC holders in that hour.[51] In contrast, congestion revenue shortfalls occur when the congestion rents the ISO owes to holders of TCCs exceed the congestion revenue it collects in an hour of the Day-Ahead Market.[52] Under the proposed ISO Tariff, all excess congestion revenues collected during a month will be used to fund any shortfall in the congestion rents needed to pay TCC holders during the month.[53] The amount by which excess congestion revenues exceed the shortfall in the congestion rents needed to pay TCC holders will be distributed to the Transmission Providers. The investor-owned Transmission Providers will use it as an offset to their TSC, while NYPA will use it as an offset to NTAC. If the shortfall in the congestion rents needed to pay TCC holders exceeds excess congestion revenues for a month, the difference will also be allocated among the Transmission Providers and included in the TSCs (NYPA's allocation will be included in NTAC).

The allocation of this excess congestion revenue (or shortfall) among the Transmission Providers is based on applying the Interface MW-Mile Methodology to the results of the TCC auction. The allocation factor for each Transmission Provider is its share of the revenue from the centralized TCC auction that is allocated using the Interface MW-Mile Methodology.[54] For

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51 The ISO may also collect excess congestion revenues in the Real-Time Market if it collects congestion charges that exceed its day-ahead financial commitments. See footnote 45 for a description of excess congestion rents.

52 The ISO may also have a congestion rent shortfall in the Real-Time Market. In particular, this may occur when a transmission outage or unusually high loop flow occurs after the Day-Ahead Market.

53 Congestion rent shortfalls that occur in the Real-Time Market will be recovered through the Scheduling, System Control and Dispatch ancillary service charge. See ISO Tariff, Schedule 1.

54 The Interface MW-Mile Methodology is used to allocate all TCC auction revenue that remains after paying all TCC holders that released and sold specific point-to-point TCCs in the auction, such as Grandfathered TCCs or Residual TCCs. Under the Interface MW-Mile Methodology, the revenue for all of the other TCCs sold in the auction will first be allocated to a predefined set of interfaces. Revenue allocated to each interface will then be allocated among the Transmission Providers in proportion to the MW-Miles that an energy transaction associated with the TCC would travel on each Transmission Provider's transmission facilities on either side of the interface. The proportion of the

example, if Transmission Provider A received 40 percent of the total revenue that was allocated using the Interface MW-Mile Methodology in the last TCC auction, then it would receive 40 percent of the net excess congestion revenues collected (or would pay 40 percent of the net congestion revenue shortfall) in each month until the next TCC auction, at which time its allocation factor would be recalculated.

A22. Explain how a customer can lock in a fixed net transmission price in advance through TCCs and the associated congestion rents.

A customer holding a TCC is assured that the price of delivering 1 MW from the point of injection to the point of withdrawal specified in the TCC will not be affected by congestion. TCCs provide the financial equivalent of firm transmission because the formula used to calculate the congestion charge for a 1 MW transaction that is scheduled a day ahead is the same as the formula used to calculate the congestion rents paid to the holder of a TCC between the injection and withdrawal points for the transaction. If the injection and withdrawal locations of a TCC match the locations used in a 1 MW bilateral transaction scheduled a day ahead, then the congestion charge for the bilateral transaction will be exactly equal to the congestion rents paid to the TCC holder, regardless of what the congestion charge actually turns out to be. A customer is completely insulated from fluctuations in congestion charges for transactions that it has hedged with TCCs, so long as it is schedules the transaction a day ahead and the number of megawatts transacted matches the number of megawatts of TCCs that it owns.[55] See responses to Questions A4 and A7.

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total revenue received by each Transmission Provider in the TCC auction defines its Interface MW-Mile sharing percentage until the next auction. See Attachment K to the ISO Tariff.

55 Using the notation defined in the response to Question A4, the congestion charge for a bilateral transaction in which *X* MW are injected at bus j and withdrawn at bus i is equal to *X* MW * (congestion component of LBMP for the zone in which the bilateral load bus is located – congestion component of the LBMP at the bilateral generator's bus) = $X * (\gamma_i^{C,Z} - \gamma_j^{C})$. The congestion rent payment made to the Primary Holder of *X* TCCs whose injection and withdrawal locations match those of the bilateral transaction is: number of TCCs * (congestion component of LBMP for the zone in which the bilateral load bus is located – congestion component of the LBMP at the bilateral generator's bus) $= X * (\gamma_i^{C,Z} - \gamma_j^{C})$, matching the congestion charge previously calculated.

[Question A23 concerns the "target allocation" and does not apply to the New York ISO Tariff proposal.]

A24. Explain whether and how a holder of TCCs can avoid paying congestion charges and yet still receive congestion rents. Give an example.

Congestion charges will be paid by each market participant based on its use of the system, without regard to whether or not it owns TCCs. No customer that is actually taking energy in an hour can avoid paying congestion charges, with the exception of customers with Grandfathered Rights. See responses to Questions A7 and A9. However, congestion rents will be paid to (or by) holders of TCCs regardless of whether and how they actually use the system. Therefore, the entities that pay transmission congestion charges and those that receive congestion rents may not be the same.

The following example illustrates how a TCC holder may be paid congestion rents that exceed its congestion charges. Suppose Transmission Customer 1 holds 100 TCCs (i.e., 100 TCCs of 1 MW denomination) between a generator at bus A and its load at bus B to support a bilateral contract for energy. If Transmission Customer 1 expects its demand to be 90 MW, it might schedule a 90 MW firm bilateral transaction from A to B and pay the day-ahead TUC for 90 MW. Assuming that the customer's actual consumption is also 90 MW and the generator serving the bilateral contract at bus B produces 90 MW, it would make no other payments to the ISO. However, even though its scheduled and actual consumption are 90 MW, Transmission Customer 1 would be paid congestion rents for the full 100 TCCs that it owns.

The fact that a TCC holder can receive congestion rents even though it has not paid a corresponding congestion charge does not come from any ability to artificially avoid paying congestion charges but, rather, occurs because the receipt of congestion rents is not tied to actual use of the system. This is one of the principal advantages of TCCs compared to physical transmission rights.[56] TCCs are financial rights to the congestion rents generated by charging LBMPs for use of a congested transmission grid. They are not physical reservations for transmission capacity. Because TCCs are financial rights, the holder of a TCC does not have to match its usage of the system to the TCC in order to appropriate the value of the right. Physical

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56 January Hogan Affidavit, pp. 70-72.

transmission rights typically only have value if a transmission customer actually uses the right for a transaction or resells it. Such an arrangement makes it difficult for the customer to alter its supply arrangements quickly when it is financially advantageous (and economically efficient) to do so. In contrast, the holder of a TCC does not have impediments to its choice of supply arrangements. Because the holder of a TCC is paid the market-clearing value of its TCC (the congestion rent) irrespective of the energy transactions it actually undertakes, it will have an incentive to search for the lowest-cost supply. In practice, it is expected that this will provide efficient incentives so that the decentralized actions and choices (e.g., whether to put a generating unit on dispatch) of market participants will lead (approximately) to an economically efficient dispatch.

A25. Provide an energy accounting example to illustrate the concept of implementing LBMP energy pricing and congestion transmission pricing. Cross-reference the specific portions of the tariff that implement the concepts illustrated in the example.

Please refer to the billing example contained in Exhibit 2, "Billing Example to Illustrate LBMP Energy and Transmission Pricing." This example is cross-referenced to the sections of the ISO Tariff that implement the concepts that are illustrated.

Further affiant saith not.

Susan L. Pope

Susan L. Pope

Signed and sworn to before me on this 12th day of December 1997.

Notary Public

Exhibit 1: Commission Staff Appendix A Questions

in Docket Nos. OA97-261-000

and ER97-1082-000

Pope Testimony

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

MAR 28 1997

COPY

Docket Nos. OA97-261-000
and ER97-1082-000

PJM Interconnection Association
ATTN: Mr. Phillip G. Harris, President
955 Jefferson Avenue
Norristown, Pennsylvania 19403-2497

Dear Mr. Harris:

By letter dated December 31, 1996, you submitted for filing with the Commission a pool-wide open access transmission tariff and a reformed pooling agreement for the PJM Interconnection (PJM). Your proposal presented two options (the PECO option and the Supporting Companies' option) for certain tariff provisions. In its February 28, 1997, order in MidContinent Area Power Pool, et al., 78 FERC ¶ 61,203 (1997), the Commission directed you to implement, subject to refund, the PECO option for congestion pricing and the Supporting Companies' option for all other matters. The Commission stated that it will convene a technical conference to resolve questions on how the Supporting Companies' option on congestion pricing could be implemented and on what modifications would make it workable.

Pursuant to these directives, please provide the information shown on Appendix A. So that the information can be used to prepare for the technical conference the Commission intends to schedule, provide it within 15 days of the date of this letter. In addition, please provide the revenue comparison data shown on Appendix B within 60 days of the date of this letter. Submit 14 copies of your response to:

Federal Energy Regulatory Commission
Office of the Secretary
888 First St, NE
Washington, DC 20426

Sincerely,

Donald J. Gelinas

Donald J. Gelinas, Director
Division of Applications

9704030321

FERC DOCKETED
MAR 28 1997

A1. The filing mentions two models used to develop energy prices: the State Estimator and the Locational Price Model. Describe the models. Explain how they are related. Also explain how the output from one model feeds into the other.

A2. Provide a detailed description of the information that will be required in submitting a bid. If a standard format for submitting bid information will be required, describe the format and provide an example.

A3. Explain whether, in any given hour, a buyer and seller located at the same bus face the same energy price. If they do not face the same price, explain the basis for the difference.

A4. Explain whether congestion charges will be determined differently for network customers and for point-to-point customers.

A5. Explain whether any transmission user will be exempt from paying congestion charges for any use of the transmission system. If so, provide the basis for this exemption.

A6. Explain whether loop flow resulting from PJM's interconnections with utilities outside of PJM will affect the congestion charges. Explain how your rate proposal accounts for this.

A7. Explain how a customer subject to a congestion charge will be able to determine the amount of the congestion charge in advance of its transaction. Compare the amount of advance notice given for the specific amount of a congestion charge to the scheduling deadlines in the tariff. To the extent a customer would not have the information before the scheduling deadline or before the transaction commences, explain how the customer will be able to obtain this information. If the customer will not be able to obtain this information before committing to a transaction, explain how the customer will be able to make efficient decisions about whether to undertake a transmission transaction.

A8. Explain whether non-firm customers can indicate in advance a threshold price for congestion payments that they are willing to pay, and above which they would be willing to be curtailed.

A9. Explain whether it is possible for a transaction to contribute to congestion and yet not be subject to a congestion charge.

A10. Explain how fixed transmission rights (FTRs) will initially be allocated by the Office of the Interconnection.

A11. It appears that the FTRs are path specific. Provide a list of the FTRs that will be allocated accompanied by a description sufficient to identify the specific path.

A12. Explain whether there will be any charge to acquire FTRs from the Office of the Interconnection.

A13. Show how the FTRs would be allocated if they tracked current transmission use entitlements by virtue of ownership or contract. To the extent you indicate a contractual right, identify the rate schedule which governs the transmission entitlement. Explain whether the initial allocation of FTRs could reflect something other than the current usage rights.

A14. Explain how the Office of the Interconnection will determine whether a given set of FTRs can feasibly be distributed.

A15. Explain how the Office of the Interconnection can ensure that the total FTRs allocated to customers can always be feasibly supported by the grid at every moment in time.

A16. Address the possibility that the total FTRs that are requested cannot feasibly be supported by the grid and explain how the requests of individual customers will be modified or curtailed.

A17. Once FTRs are initially allocated, explain how will new FTRs will be allocated.

A18. Explain how the allocation of new FTRs affect existing FTRs.

A19. Explain how FTRs for expansions to the grid be distributed.

A20. Explain how revenues from congestion revenues will be distributed to FTR holders. Explain whether FTR holders could take actions that would change the paths for which they hold FTRs from unconstrained to constrained paths.

A21. Explain the rationale for distributing "excess congestion revenues" exclusively to network FTR holders and not to point-to-point FTR holders.

A22. Explain how a customer can lock-in a fixed net transmission price in advance through FTRs and the associated congestion revenues.

A23. Explain the "target allocation" and how this impacts FTR revenue distributions.

A24. Explain whether and how a holder of FTRs can avoid paying congestion revenues and yet still receive congestion revenues. Give an example.

A25. The Brief of the Supporting Companies ("Energy Accounting Example for the PJM Supporting Company Regional Energy Market Model") is intended to illustrate the concept of implementing nodal energy pricing and congestion transmission pricing. Cross-reference the specific portions of the tariff that implement the concepts illustrated in the example.

Exhibit 2: Response to Question A 25

Billing Example to Illustrate

LBMP Energy and Transmission Pricing

Pope Testimony

Objectives

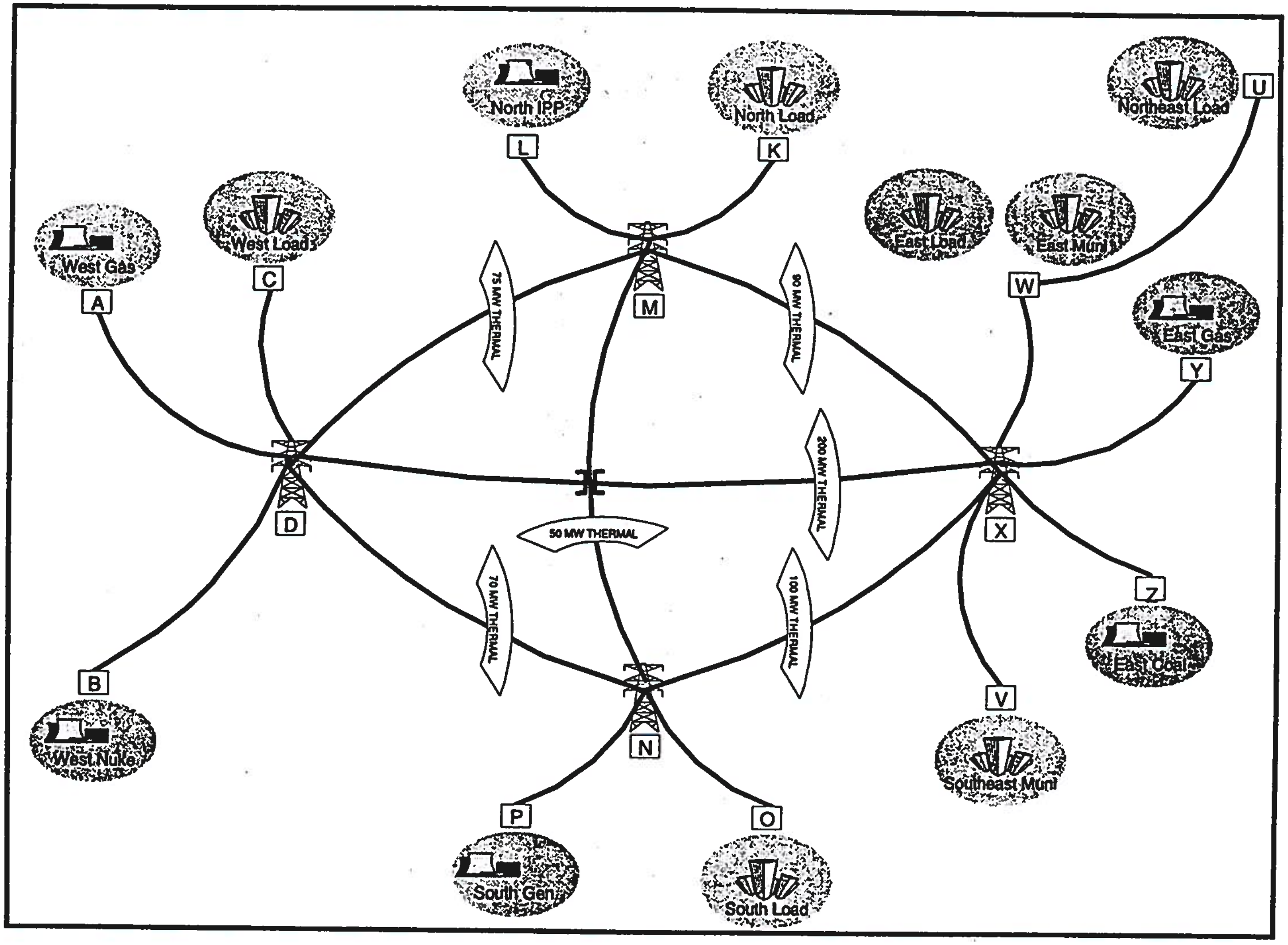
This exhibit presents an accounting example to illustrate the implementation of LBMP pricing of energy and transmission usage. The exhibit will:

- Show how the ISO will use LBMPs to charge LSEs buying from the ISO-facilitated LBMP market and to pay generators selling into the ISO-facilitated LBMP market.
- Show how the ISO will calculate the transmission usage charge (TUC) that is charged to bilateral transmission customers and demonstrate that the TUC is calculated from the same LBMPs used to bill ISO market participants.
- Show the congestion and loss components of the LBMP and the TUC.
- Show how the ISO will calculate the congestion rents that it pays to holders of TCCs.

The accounting example has the following sections:

- Introduction of an illustrative transmission system.
- Allocation of an illustrative set of TCCs.
- Introduction of a solved energy dispatch for this transmission system and of the LBMPs corresponding to the energy dispatch.
- Calculation of charges paid by:
  - LSEs buying from the ISO-facilitated LBMP market.
  - Bilateral transmission customers.
- Calculation of payments made to:
  - Generators selling into the ISO-facilitated LBMP market.
  - Holders of TCCs.
- Calculation of excess congestion rents and the residual adjustment collected by the ISO.
- Summary of charges and payments.
- Exhibits:
  - Exhibit 2A: Feasibility Test for Illustrative Allocation of TCCs.
  - Exhibit 2B: Explanation for Calculation of LBMPs.

ILLUSTRATIVE TRANSMISSION SYSTEM



TRANSMISSION SYSTEM

Physical Characteristics

The illustrative example assumes a transmission system with the following physical characteristics:

- It has thermal constraints of 75 MW between Buses D and M; 70 MW between Buses D and N; 200 MW between Buses D and X; 50 MW between Buses N and M; 90 MW between Buses M and X; and 100 MW between Buses N and X.
- The outage of the 200 MW line between Buses D and X is generally the contingency that causes a constraint to bind in the security-constrained dispatch.[1,2]
- For simplicity, all transmission lines connecting Buses D, M, N and X have the same physical characteristics (i.e., they have equal resistance and reactance). Radial lines have differing physical characteristics.

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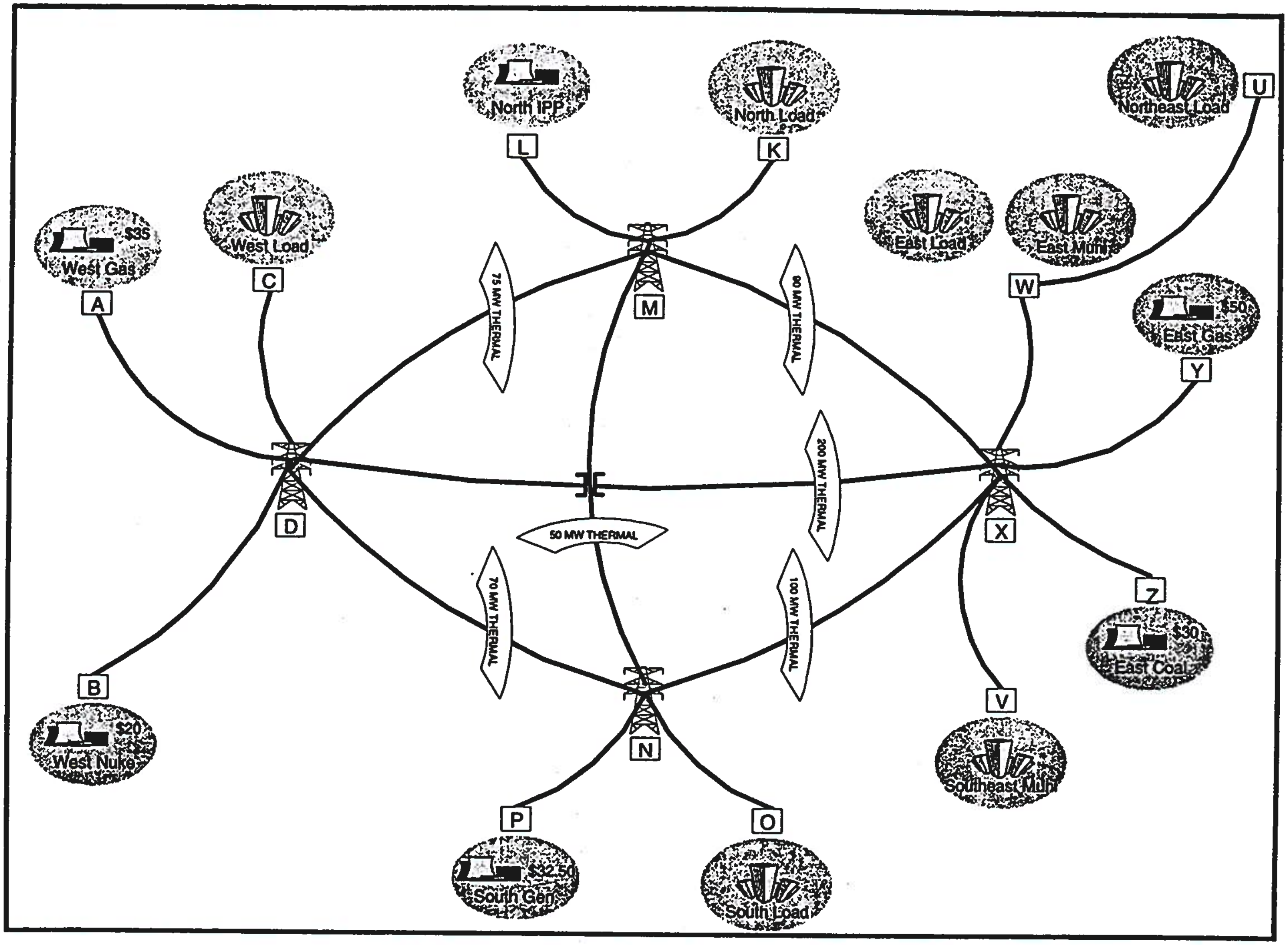
1 For simplicity, all diagrammatic representations of the dispatch of the transmission system that follow will show the system without the D-X line, because the outage of this line is the limiting contingency.

2 For an explanation of contingency constraints, please see Appendix A of "Report on the Proposal to Restructure the New York Electricity Market," William W. Hogan, January 31, 1997.

ILLUSTRATIVE TRANSMISSION SYSTEM



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

The illustrative example also assumes that the following generation facilities are available and that they typically make the following incremental bids to produce energy when they have capacity available that is not under bilateral contract:[3]

- West Nuke -- $20/MWh (100 MW at Bus B).
- North IPP -- $30/MWh (25 MW at Bus L).
- East Coal -- $30/MWh (100 MW at Bus Z).
- South Gen -- $32.50/MWh (100 MW at Bus P).
- West Gas -- $35/MWh (100 MW at Bus A).
- East Gas -- $50/MWh (100 MW at Bus Y).

The example assumes that North IPP has a power purchase contract with Southeast Muni and East Coal has a power purchase contract with East Muni.

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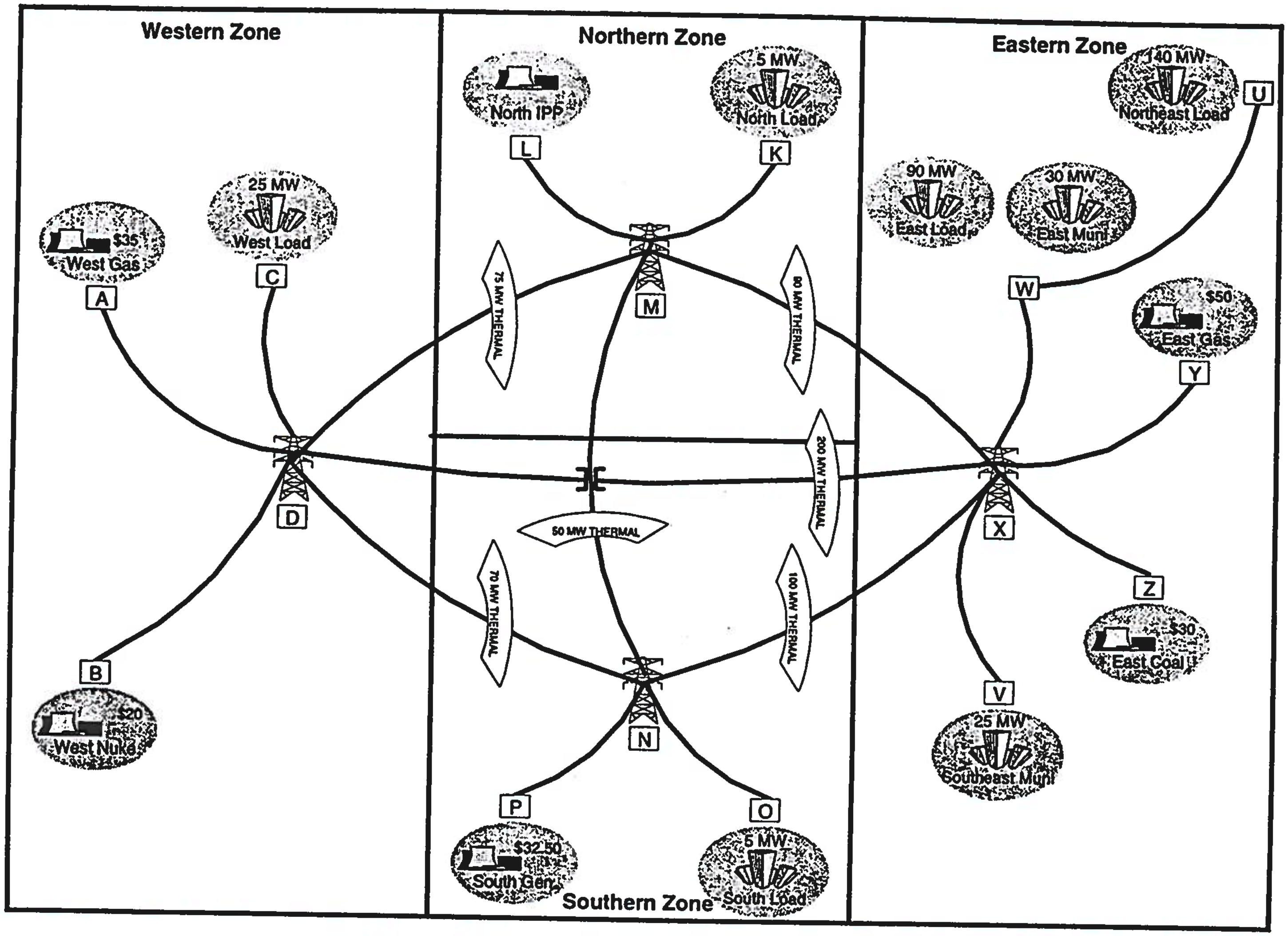
3 For simplicity, the examples assume that there are no start-up costs and that generators do not have minimum generation levels. Additionally, operating reserves will not be scheduled. All of these characteristics of an actual schedule could be included in the example without affecting the results.

ILLUSTRATIVE TRANSMISSION SYSTEM



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

The illustrative example will assume that LSEs commit to purchasing the following amounts of energy in the day-ahead dispatch:

- Southeast Muni -- 25 MW at Bus V served by power purchase agreement.
- East Muni -- 30 MW at Bus W served by power purchase agreement.
- Wholesale LSE -- purchases from LBMP market:
  - East Load -- 90 MW at Bus W.
  - Northeast Load -- 140 MW at Bus U.
  - West Load -- 25 MW at Bus C.
  - North Load -- 5 MW at Bus K.
  - South Load -- 5 MW at Bus O.

The diagram shows illustrative zones that will be used to calculate the zonal LBMPs that LSEs will pay for energy purchased from the ISO-facilitated LBMP market.

Loads will be permitted to bid prices into the day-ahead schedule; if the LBMP price in the day-ahead schedule exceeds that price, that load would not be included in the day-ahead schedule. For simplicity, however, this example will assume that all loads place high enough bids so that they are served.

Illustrative Allocation of TCCs				
Contract Number	From Bus	To Bus	Number of TCCs	Holder
1	A	C	25	Wholesale LSE
2	B	U	100	Wholesale LSE
3	P	O	5	Wholesale LSE
4	A	U	40	Wholesale LSE
5	Y	W	10	Wholesale LSE
6	Z	W	60	Wholesale LSE
7	L	V	20	Southeast Muni
8	P	W	20	Wholesale LSE
9	L	K	5	Wholesale LSE

Grandfathered Rights				
Contract Number	From	To	MW	Holder
10	Z	W	40	East Muni

ALLOCATION OF TCCs

Illustrative

The table above shows an illustrative allocation of TCCs and Grandfathered Rights for the transmission system.

- The TCCs may have been obtained from:[4]
  - The conversion of existing transmission agreements to TCCs (Grandfathered TCCs).[5]
  - An allocation of TCCs based on native load obligations (Native Load TCCs).[6]
  - An allocation of Residual TCCs.
  - The centralized TCC auction.[7]
- The Grandfathered Rights are obtained from retaining the rights under an existing transmission agreement.[8] East Muni has kept its existing transmission agreement as a Grandfathered Right while the Southeast Muni has converted its existing right to a Grandfathered TCC.

Exhibit 2A demonstrates the feasibility of this illustrative allocation of TCCs and Grandfathered Rights.

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4 TCCs may also be obtained from Transmission Providers (and others) that are selling TCCs over the OASIS, or through a secondary market purchase.

5 Sections 2 and 4 of Attachment G of the New York State ISO Tariff.

6 Section 2.5 of Attachment G of the New York State ISO Tariff.

7 Section 6 of Attachment M of the New York State ISO Tariff.

8 Sections 2 and 3 of Attachment G of the New York State ISO Tariff.

The example will be based on the dispatch and LBMPs for one hour. For simplicity, it assumes that the real-time dispatch for this hour is the same as the day-ahead schedule, so that settlements only need to be shown for the day-ahead market.

The schedule for the day-ahead market consists of bilateral transaction schedules and schedules for LSEs and generators participating in the ISO-facilitated market. Assume that the following transactions are announced[9] to the ISO before the day-ahead schedule:

- Wholesale LSE schedules a 100 MW bilateral transaction between Northeast Load at Bus U and West Nuke at Bus B.
- Southeast Muni schedules a 20 MW bilateral transaction between its location at Bus V and North IPP at Bus L. Southeast Muni converted its transmission rights associated with its power purchase contract into a Grandfathered TCC.
- East Muni schedules a 30 MW bilateral transaction between its location at Bus W and East Coal at Bus Z. East Muni has a 40 MW Grandfathered Right from Bus Z to Bus W.

Note that East Muni has scheduled only 30 MW of its potential 40 MW Grandfathered Right. Because East Muni chose to retain Grandfathered Rights it cannot collect the congestion rents that may accrue to the remaining 10 MW of its right during the dispatch of the system.[10]

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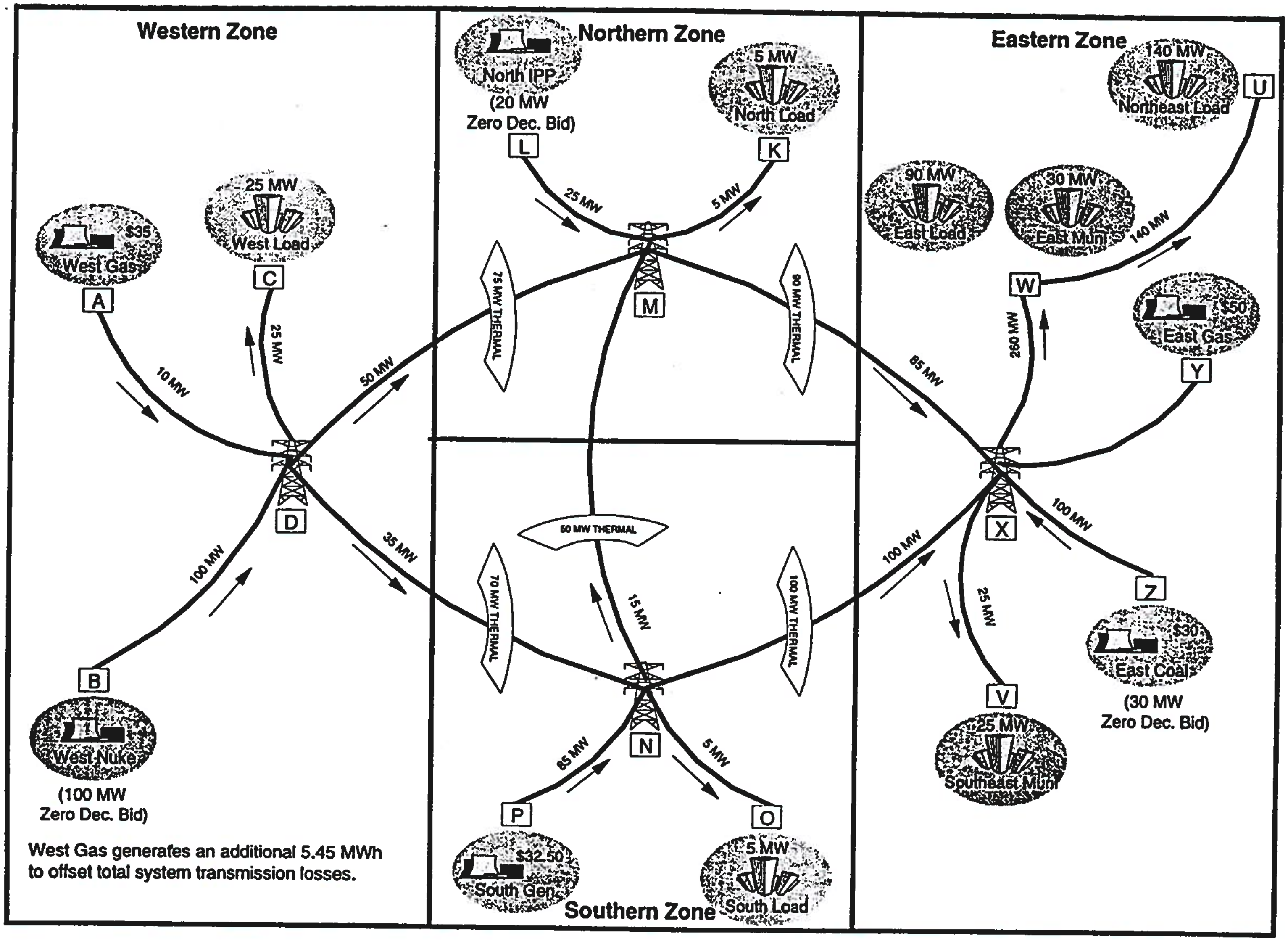
9 This would be done in accordance with Section 4.10 of the New York State ISO Tariff. The ISO would post the resulting day-ahead schedule in accordance with Section 4.14 of the New York State ISO Tariff.

10 The differing treatment of Grandfathered Rights and Grandfathered TCCs is discussed in Sections 3 and 4 of Attachment G of the New York State ISO Tariff.

We will assume that each of the generators serving bilateral contracts makes a zero decremental bid into the day-ahead schedule for the amount of energy needed to serve the load scheduled day-ahead under its bilateral transaction. By making a zero decremental bid, each generator ensures that it will be scheduled to generate enough energy to serve its bilateral contract unless the LBMP at its bus is less than zero.

So, West Nuke makes a zero decremental bid to produce 100 MW, North IPP makes a zero decremental bid to produce 20 MW, and East Coal makes a zero decremental bid to produce 30 MW. North IPP and East Coal make the incremental bids specified earlier for their remaining capacity that is not used to serve their bilateral contracts.

CONSTRAINED DAY-AHEAD DISPATCH



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

Description of the Dispatch

Generation Dispatch			
Generator	Total Generation (MW)	Bilateral Contracts (MW)	LBMP Market (MW)
West Gas	10	0	10
West Nuke	100	100	0
North IPP	25	20	5
South Gen	85	0	85
East Coal	100	30	70
East Gas	0	0	0
Total	320	150	170

Load Dispatch			
Load	Total Load (MW)	Bilateral Contracts (MW)	LBMP Market (MW)
West Load	25	0	25
North Load	5	0	5
South Load	5	0	5
Southeast Muni	25	20	5
East Load	90	0	90
East Muni	30	30	0
Northeast Load	140	100	40
Total	320	150	170

The dispatch to meet a total of 320 MWh of load is shown above, in the contingency in which the line connecting Buses D and X fails. In this contingency, the thermal constraint on the line connecting Buses N and X binds, causing transmission congestion. Two generators are on the margin in this dispatch. West Gas generates 10 MWh, while South Gen generates 85 MWh. Although it would be less expensive to dispatch South Gen to generate more energy and for West Gas to generate less, doing so would cause violations of thermal limits in the illustrated contingency. As a consequence, South Gen generates only 85 MWh in the contingency-constrained least-cost dispatch.

East Muni scheduled only 30 MW of its 40 MW Grandfathered Right, while Southeast Muni, in addition to scheduling a 20 MW bilateral contract to match its Grandfathered TCC, schedules 5 MW of spot market load.

Since LBMPs at all locations are positive, each generator that made a zero decremental bid is scheduled to generate at least the amount of energy specified in that decremental bid. In fact, both North IPP and East Coal generate energy in association with their incremental bids as well.

Calculation of LBMPs at All Buses				
Bus	Locational Price ($/MWh)	Reference Bus Price ($/MWh)	Losses Relative to Reference Bus ($/MWh)	Congestion Relative to Reference Bus ($/MWh)
A	35.00	35.00	-	-
B	34.30	35.00	(0.70)	-
C	35.15	35.00	0.15	-
D	35.06	35.00	0.06	-
K	37.53	35.00	0.09	2.44
L	37.41	35.00	(0.03)	2.44
M	37.50	35.00	0.06	2.44
N	32.62	35.00	0.06	(2.44)
O	32.63	35.00	0.07	(2.44)
P	32.50	35.00	(0.06)	(2.44)
U	46.31	35.00	1.56	9.75
V	44.92	35.00	0.17	9.75
W	45.40	35.00	0.65	9.75
X	44.85	35.00	0.10	9.75
Y	44.85	35.00	0.10	9.75
Z	44.78	35.00	0.03	9.75

The LBMP can be decomposed into three components through the use of the following equation.[11]

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

where:

γ_i = LBMP at Bus i.

λ^R = The system marginal bid price at the reference bus.

γ_i^L = Loss component of the LBMP at Bus i, which is the marginal cost of losses at Bus i relative to the reference bus.

γ_i^C = Congestion component of the LBMP at Bus i, which is the marginal cost of congestion at Bus i relative to the reference bus.

The table on the facing page shows the LBMPs for each bus on the system broken into the three components described above.[12]

11 The calculation of LBMPs is also discussed in Attachment I of the New York State ISO Tariff.

12 LBMPs can also be calculated at a bus by redispatching the system with an increment of load added at that bus. Exhibit 2B to this exhibit shows this calculation for Bus U and Bus K.

The loss component of the LBMP, γ_i^L, is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

where:

DF_i = delivery factor for Bus i from the system reference bus.[13]

The congestion component of the LBMP at Bus i is calculated using the equation:

$$\gamma_i^C = -\left(\sum_{k \in K} GF_{ik}\mu_k\right)$$

where:

K = The set of thermal or interface constraints.

GF_{ik} = Generation shift factor for the generator at Bus i on constraint k in the pre- or post-contingency case which limits flows across that constraint.

μ_k = The reduction in system cost that results from an incremental relaxation of constraint k.

13 A more detailed definition of the delivery factor is shown in Attachment I of the New York State ISO Tariff.

Calculation of LBMPs in All Zones				
Zone	Zonal Locational Price ($/MWh)	Reference Bus Price ($/MWh)	Zonal Losses Relative to Reference Bus ($/MWh)	Zonal Congestion Relative to Reference Bus ($/MWh)
East Zone	$ 45.80	$ 35.00	$ 1.06	$ 9.75
North Zone	$ 37.53	$ 35.00	$ 0.09	$ 2.44
South Zone	$ 32.63	$ 35.00	$ 0.07	$ (2.44)
West Zone	$ 35.15	$ 35.00	$ 0.15	$ -

The zonal LBMPs for this dispatch are shown on the facing page. They are calculated by taking a load-weighted average of the LBMPs at each load bus in a zone.[14] The Western, Northern and Southern Zones each have only one load bus. The table below shows the components of the LBMPs for each load bus in the Eastern Zone.

Components of LBMP for Eastern Zone Load Buses					
Bus	Locational Price ($\MWh)	Reference Bus Price ($/MWh)	Losses Relative to Reference Bus ($/MWh)	Congestion Relative to Reference Bus ($/MWh)	Load (MW)
U	$ 46.31	$ 35.00	$ 1.56	$ 9.75	140
V	$ 44.92	$ 35.00	$ 0.17	$ 9.75	25
W	$ 45.40	$ 35.00	$ 0.65	$ 9.75	120

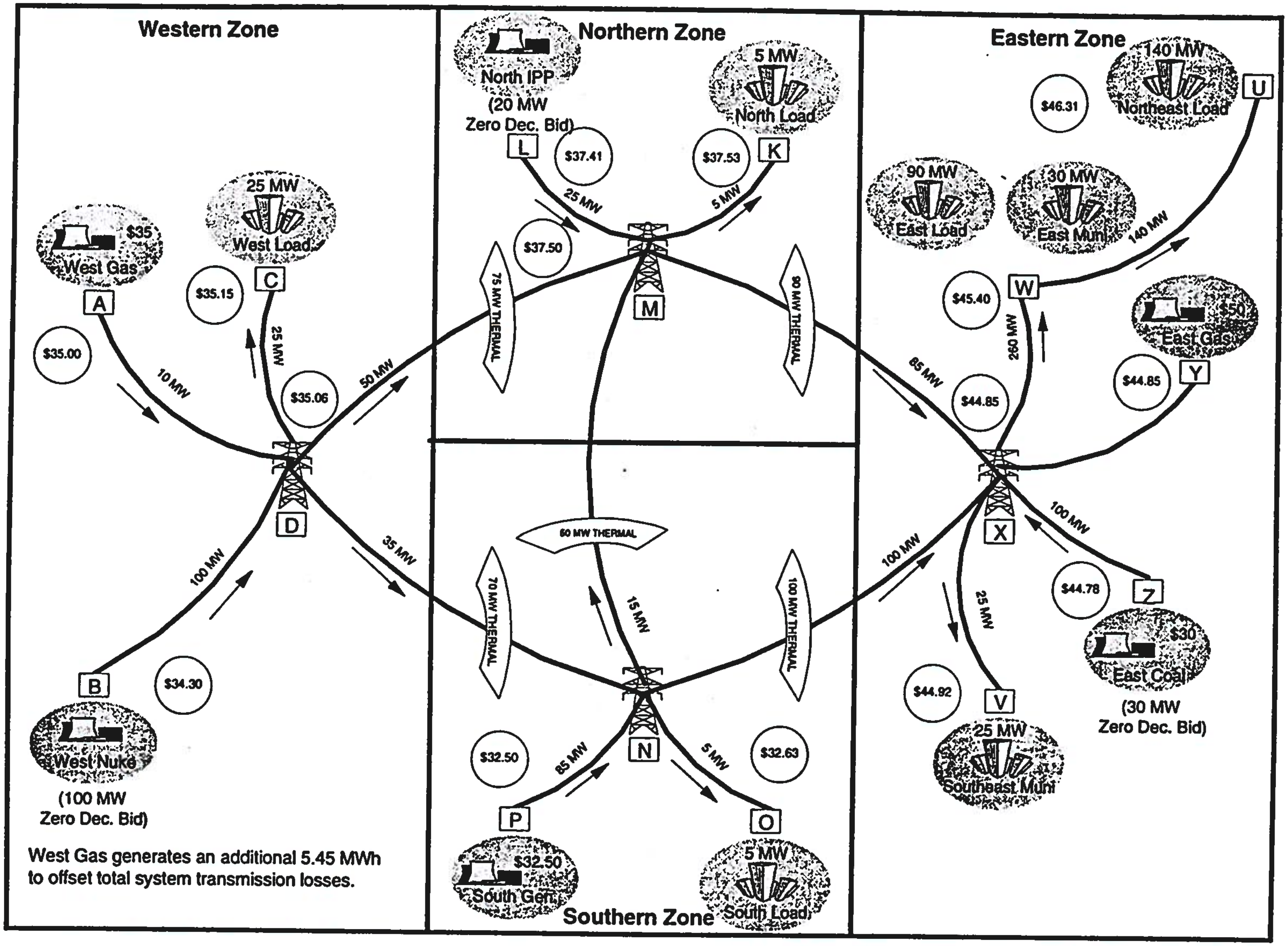
The calculation of the Eastern Zone LBMP is:

$$\$46.31 * (140 / 285) + \$44.92 * (25 / 285) + \$45.40 * (120 / 285) = \$45.80$$

The loss and congestion components of the zonal LBMP for the Eastern Zone are also computed as a weighted average of the loss and congestion components at each load bus in that zone, weighted by load at that bus.

14 The calculation of zonal LBMPs is discussed in Attachment I of the New York State ISO Tariff.

CONSTRAINED DAY-AHEAD DISPATCH



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

CHARGES PAID

The table below shows the LBMP payments made by the LSEs for energy consumed as scheduled day-ahead from the ISO-facilitated LBMP market. This is done in the Day-Ahead Settlement.[15] Note that East Muni makes no LBMP payment even though it consumed 30 MWh of energy. All of the energy East Muni consumed was provided by East Coal under a bilateral contract and is not subject to LBMP energy charges.

LBMP Charges To LSEs						
		Dispatch				
LSE	Load	Total Load (MW)	Bilateral Load (MW)	LBMP Market Load (MW)	Zonal LBMP ($/MWh)	LBMP Energy Payment ($)
Wholesale LSE	West Load	25	0	25	$ 35.15	$ 878.75
Wholesale LSE	Northeast Load	140	100	40	$ 45.80	$ 1,832.00
Wholesale LSE	North Load	5	0	5	$ 37.53	$ 187.65
Wholesale LSE	South Load	5	0	5	$ 32.63	$ 163.15
Wholesale LSE	East Load	90	0	90	$ 45.80	$ 4,122.00
East Muni	East Muni	30	30	0	$ 45.80	$ -
Southeast Muni	Southeast Muni	25	20	5	$ 45.80	$ 229.00
Total		320	150	170		$ 7,412.55

Because we have assumed that the actual dispatch exactly matches the day-ahead schedule, there are no Real-Time Energy Settlements.[16]

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15 The LBMP payments made by LSEs associated with the Day-Ahead Settlement are discussed in Section 4.27 of the New York State ISO Tariff.

16 The LBMP payments made by LSEs associated with Real-Time Energy Settlement are discussed in Section 4.29 of the New York State ISO Tariff.

The table below shows the TUC[17] payments that would be made for all bilateral transactions that do not hold Grandfathered Rights. The TUC for each MW transmitted is equal to the LBMP for the zone of the withdrawal minus the LBMP at the point of injection. It can be broken into a congestion component (equal to the congestion component of the LBMP at the zone of withdrawal minus the congestion component of the LBMP at the point of injection) and a loss component (equal to the loss component of the LBMP at the zone of withdrawal minus the loss component of the LBMP at the point of injection). Since these bilateral transactions were scheduled day ahead, the TUC they pay is based on day-ahead LBMPs.

TUC Paid by Bilateral Transactions

				LBMP ($/MWh)		
From	To	MW	Payer	Zone of Withdrawal ($/MWh)	Point of Injection ($/MWh)	TUC Payment (Credit) ($)
B	Eastern	100	Wholesale LSE	$ 45.80	$ 34.30	$ 1,150
L	Eastern	20	Southeast Muni	$ 45.80	$ 37.41	$ 168
Total TUC Collections						$ 1,317

17 The TUC is discussed in Section 4.19A of the New York State ISO Tariff.

This table shows the loss payment that would be made by East Muni, which has used a Grandfathered Right to support its bilateral transaction.[18] The loss payment for each MW transmitted is equal to the loss component of the LBMP in the zone of withdrawal minus the loss component of the LBMP at the point of injection. East Muni does not pay the congestion component of the TUC because it was allocated Grandfathered Rights sufficient to transmit the 30 MWh of energy it has purchased under its contract.

Losses Payments by Bilateral Transactions Using Grandfathered Rights						
				Loss Component of LBMP		
From	To	MW	Payer	Zone of Withdrawal ($/MWh)	Point of Injection ($/MWh)	Losses Payment (Credit) ($)
Z	Eastern	30	East Muni	$ 1.06	$ 0.03	$ 21

These payments bring total payments made by transmission-only customers to $1,338, including the $1,317 in TUC charges paid by transmission customers without grandfathered rights computed on the preceding page.

18 The losses payment and its application to existing transmission agreements is discussed in sections 3.2 and 3.3 of Attachment G of the New York State ISO Tariff.

The LBMP payments made to generators[19] selling into the ISO-facilitated LBMP market are shown in the table below.

LBMP Payments To Generators

	Dispatch				
Generator	Total Generation (MW)	Bilateral Generation (MW)	LBMP Market Generation (MW)	LBMP ($/MWh)	LBMP Payments to Generators ($)
West Gas	10	0	10	$ 35.00	$ 350.00
West Nuke	100	100	0	$ 34.30	$ -
North IPP	25	20	5	$ 37.41	$ 187.05
South Gen	85	0	85	$ 32.50	$ 2,762.50
East Coal	100	30	70	$ 30.00	$ 2,100.00
East Gas	0	0	0	$ 44.85	$ -
Total	320	150	170		$ 5,399.55

Note that West Nuke receives no payment through the LBMP market, as it scheduled its entire capacity as a bilateral transaction.

Because we have assumed that the real-time dispatch exactly matches the day-ahead schedule, there are no Real-Time Energy Settlements.[20]

19 The LBMP payments to generators associated with the Day-Ahead Settlement are discussed in Section 4.27 of the New York State ISO Tariff.

20 The LBMP payments made to generators associated with Real-Time Energy Settlement are discussed in Section 4.29 of the New York State ISO Tariff.

Payments Made To Holders of TCCs								
Description of the TCCs						Congestion Component of LBMP		
Contract Number	From	To	Quantity of TCCs	Holder	On Behalf Of	Zone of Withdrawal ($/MW)	Point of Injection ($/MW)	TCC Revenue (Payment) ($)
1	A	C	25	Wholesale LSE	West Load	$ -	$ -	$ -
2	B	U	100	Wholesale LSE	Northeast Load	$ 9.75	$ -	$ 974.79
3	P	O	5	Wholesale LSE	South Load	$ (2.44)	$ (2.44)	$ -
4	A	U	40	Wholesale LSE	Northeast Load	$ 9.75	$ -	$ 389.92
5	Y	W	10	Wholesale LSE	East Load	$ 9.75	$ 9.75	$ -
6	Z	W	60	Wholesale LSE	East Load	$ 9.75	$ 9.75	$ -
7	L	V	20	Southeast Muni	Southeast Muni	$ 9.75	$ 2.44	$ 146.22
8	P	W	20	Wholesale LSE	East Load	$ 9.75	$ (2.44)	$ 243.70
9	L	K	5	Wholesale LSE	North Load	$ 2.44	$ 2.44	$ -
Total Payment to Holders of TCCs								$ 1,754.62

Each Primary Holder of a TCC receives a payment of congestion rent (or pays congestion rent, in the case of negative congestion) based on the congestion components of the Day-Ahead LBMPs. The payment is the product of the number of TCCs held multiplied by the congestion component of the zonal LBMP at the point of withdrawal minus the congestion component of the LBMP at the point of injection.[21]

[21] The payments made to Holders of TCCs is discussed in Section 4.30 of the New York State ISO Tariff.

Congestion Rents Paid to Generators Selling in the Spot Market

Generator	Generation (MW)	Congestion Component of LBMP ($/MWh)	Congestion Payments Made ($)
West Gas	10	$ -	$ -
West Nuke	0	$ -	$ -
North IPP	5	$ 2.44	$ 12
South Gen	85	$ (2.44)	$ (207)
East Coal	70	$ 9.75	$ 683
East Gas	0	$ 9.75	$ -
Total	170		$ 487

Congestion Charges Paid by LSEs Buying from the Spot Market

LSE	Load	LBMP Load (MW)	Congestion Component of Zonal LBMP ($/MWh)	Congestion Payments Received ($)
Wholesale LSE	West Load	25	$ -	$ -
Wholesale LSE	North Load	5	$ 2.44	$ 12
Wholesale LSE	South Load	5	$ (2.44)	$ (12)
Southeast Muni	Southeast Muni	5	$ 9.75	$ 49
Wholesale LSE	East Load	90	$ 9.75	$ 878
East Muni	East Muni	0	$ 9.75	$ -
Wholesale LSE	Northeast Load	40	$ 9.75	$ 390
Total		170		$ 1,316

Congestion Charges Paid by Transmission Customers

LSE	Load	MW	Congestion Component of LBMP		Congestion Payments Received ($)
			Point or Zone of Withdrawal ($/MWh)	Point of Injection ($/MWh)	
Wholesale LSE	NorthEast Load	100	$ 9.75	$ -	$ 975
Southeast Muni	Southeast Muni	20	$ 9.75	$ 2.44	$ 146
Total		120			$ 1,121

EXCESS CONGESTION RENTS AND RESIDUAL ADJUSTMENT

The three tables on the facing page show the congestion rents paid to generators selling into the ISO-facilitated spot market, congestion charges paid by LSEs purchasing from this market and congestion charges paid by transmission customers engaging in bilateral transactions, respectively.

The excess congestion rents are the total congestion rents collected (the second and third tables above) less the congestion rents paid out to generators (the first table above) less the amount paid out to holders of TCCs ($1,755). Consequently,

Excess Congestion Rents = $1,121 + $1,316 - $487 - $1,755 = $196.[22]

The residual adjustment can be calculated by taking the total payments received by the ISO from LSEs and transmission-only customers, less the amount paid to generators selling into the spot market, less the congestion rents paid out to TCC holders, less excess congestion rents. The table below shows that the residual adjustment is $1,401.[23]

Residual Adjustment Summary					
Payments Made By		Payments Made			
LSEs Buying From the Spot Market ($)	Transmission Customers ($)	Generators Selling to the Spot Market ($)	TCC Holders ($)	Excess Congestion Rents ($)	Residual Collections ($)
$ 7,413	$ 1,338	$ 5,400	$ 1,755	$ 196	$ 1,401

22 May not add up due to rounding.

23 The residual adjustment is deducted from the amount collected through the Scheduling, System Control and Dispatch Service charge, as described in Schedule 1 of the New York ISO Tariff.

SUMMARY OF CHARGES AND PAYMENTS

Summary Of ISO Charges and Payments to LSEs											
LSE	Load ($)	Zone	Type of Load	Load in the Hour (MW)	Day-Ahead Zonal LBMP ($/MWh)	Transmission Usage Charge ($/MWh)	Losses Payment ($/MWh)	Total Charges from the ISO ($/MWh)	TCC Revenues (Payments) ($/MWh)	TCC Contract Number	Net Charge ($/MWh)
Wholesale LSE	West Load	West	LBMP	25	$ 35.15			$ 35.15	$ -	1	$ 35.15
Wholesale LSE	East Load	East	LBMP	90	$ 45.80			$ 45.80	$ 2.71	5, 6 and 8	$ 43.10
Wholesale LSE	Northeast Load	East	LBMP	40	$ 45.80			$ 45.80	$ 9.75	4	$ 36.05
Wholesale LSE	North Load	North	LBMP	5	$ 37.53			$ 37.53	$ -	9	$ 37.53
Wholesale LSE	South Load	South	LBMP	5	$ 32.63			$ 32.63	$ -	3	$ 32.63
Wholesale LSE	Northeast Load	East	Bilateral	100		(45.80 - 34.30) = $11.50		$ 11.50	$ 9.75	2	$ 1.75
East Muni	East Muni	East	Bilateral	30			1.06 - 0.03 = 1.02	$ 1.02			$ 1.02
Southeast Muni	Southeast Muni	East	Bilateral	20		(45.80 - 37.41) = $8.39		$ 8.39	$ 7.31	7	$ 1.08
Southeast Muni	Southeast Muni	East	LBMP	5	$ 45.80			$ 45.80			$ 45.80

The table above summarizes all of the charges paid by the LSEs to the ISO and all revenues paid by the ISO to the LSEs in the day-ahead schedule. It excludes all payments made under bilateral contracts. It also excludes the cost of obtaining TCCs. The shaded portions of the table represent payments that do not apply to that particular transaction. Blank spaces in the table represent market participants who, through their choice, chose not be involved in that aspect of the market.

Other charges, not covered in this exhibit, include:

- Transmission Service Charges (TSC),[24]
- NYPA Transmission Adjustment Charge (NTAC),[25]
- Ancillary Services Charges,[26] and
- Stranded Investment Recovery Charge.

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24 The TSC is discussed in Section 4.19B and Attachment B.

25 The NTAC is discussed in Section 4.19C and Attachment C.

26 Charges for Ancillary Services are discussed in Sections 4.20 through 4.26 and Schedules 1 through 6 of the New York State ISO Tariff.

Exhibit 2A: Feasibility Test

for Illustrative Allocation of TCCs

Pope Testimony

Illustrative Allocation of TCCs				
Contract Number	From Bus	To Bus	Number of TCCs	Holder
1	A	C	25	Wholesale LSE
2	B	U	100	Wholesale LSE
3	P	O	5	Wholesale LSE
4	A	U	40	Wholesale LSE
5	Y	W	10	Wholesale LSE
6	Z	W	60	Wholesale LSE
7	L	V	20	Southeast Muni
8	P	W	20	Wholesale LSE
9	L	K	5	Wholesale LSE

Grandfathered Rights				
Contract Number	From	To	MW	Holder
10	Z	W	40	East Muni

ALLOCATION OF TCCs

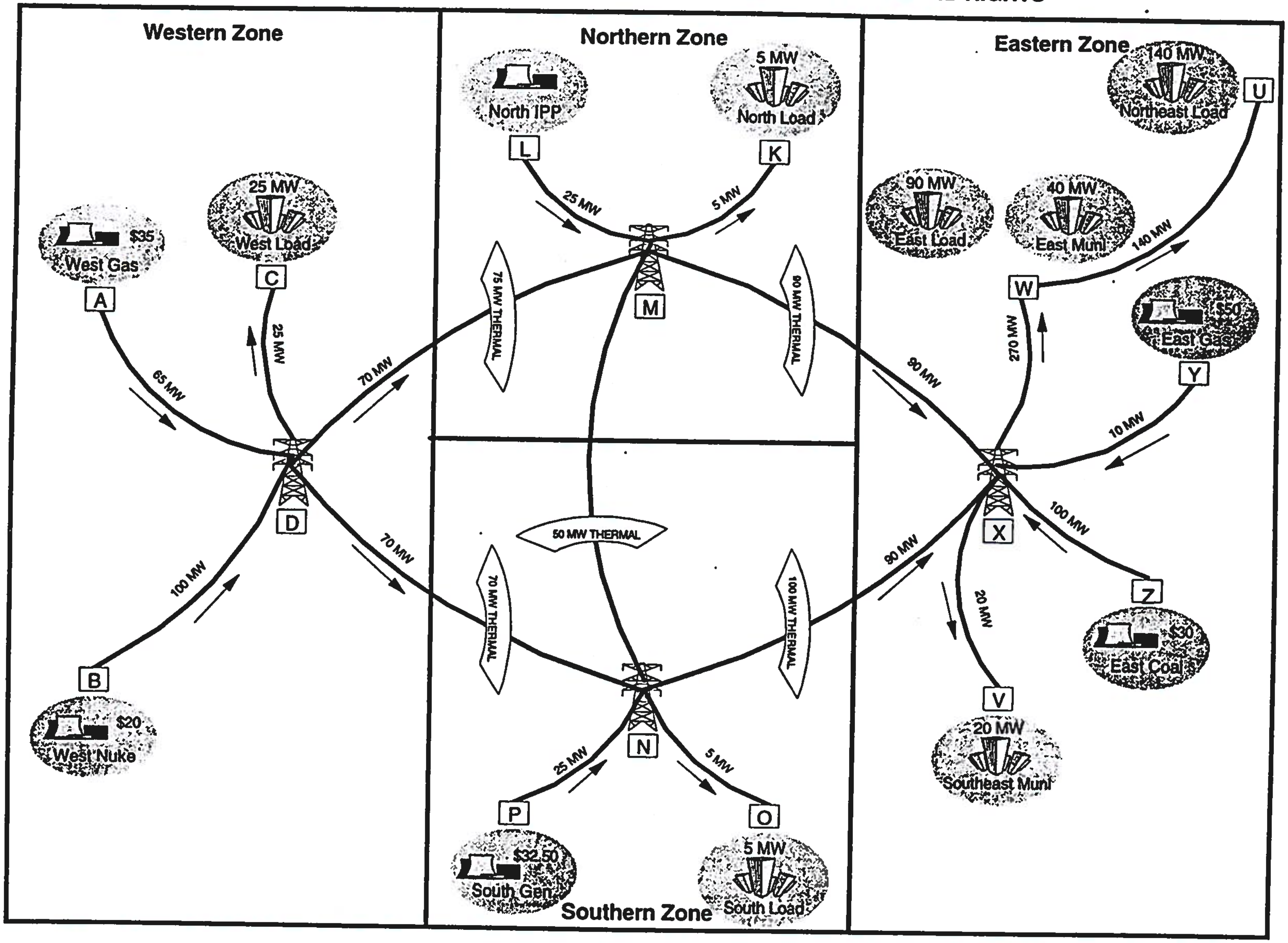
Feasibility

The set of TCCs and Grandfathered Rights initially allocated for this transmission system should be simultaneously feasible. Simultaneous feasibility means that if each owner of a TCC or Grandfathered Right were to use it to support an energy transaction, the resulting physical flows of energy would not violate any transmission limits in a security-constrained dispatch. The following table sums the injections and withdrawals at each bus for the illustrative allocation of TCCs and Grandfathered Rights.

INITIAL ALLOCATION OF TCCs AND GRANDFATHERED RIGHTS

Contract Number	Point of Injection (MW)						Point of Withdrawal (MW)					
	Bus A	Bus B	Bus L	Bus P	Bus Y	Bus Z	Bus C	Bus K	Bus O	Bus U	Bus V	Bus W
1	25						25					
2		100								100		
3				5					5			
4	40									40		
5					10							10
6						60						60
7			20								20	
8				20								20
9			5					5				
10						40						40
TOTAL (MW)	65	100	25	25	10	100	25	5	5	140	20	130

LOAD FLOW CORRESPONDING TO INITIAL ALLOCATION OF TCCs AND GRANDFATHERED RIGHTS



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

The accompanying figure shows that the energy flows that would result from dispatching the system to match the injections and withdrawals defined by the initial set of TCCs and Grandfathered Rights is simultaneously feasible. This is because:

- The energy flows do not violate any thermal transmission limits, although two transmission lines, between Buses D and N and Buses M and X, are fully loaded to their thermal limits in the binding contingency, which is the outage of the 200 MW line from Bus D to Bus X.

- The energy flows also obey Kirchhoff's Laws, which means that the sum of the flows around any loop in the transmission system (e.g., Bus D to Bus M to Bus N and back to Bus D) must sum to zero.[27] The energy flows on the transmission system will always distribute themselves to obey Kirchhoff's Laws, which is why changes in injections or withdrawals at one bus may change the energy flows everywhere on the system and, hence, affect the feasibility of other uses of the system.

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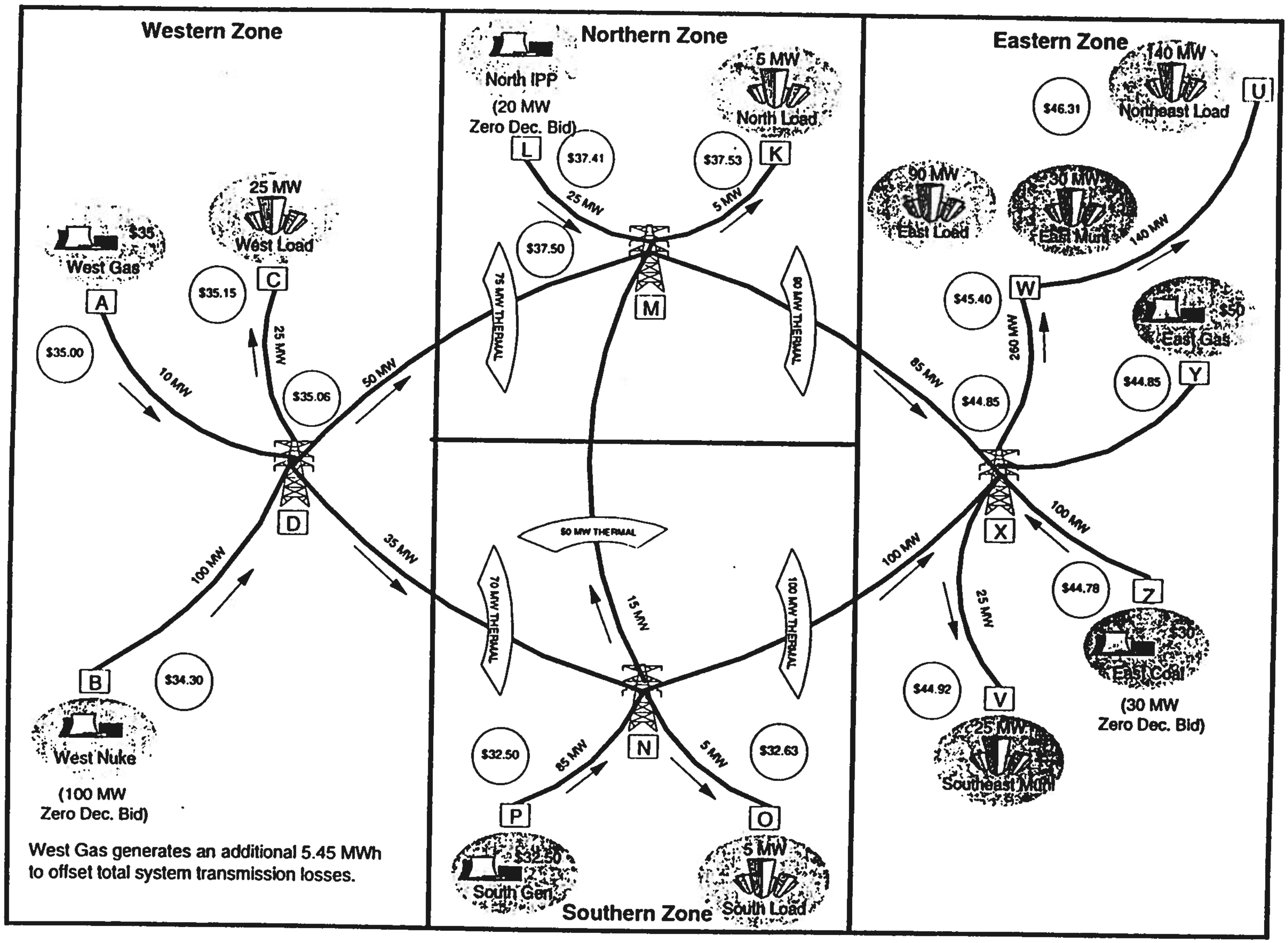
27 In a real system, in which the resistance and reactance of each transmission line are not the same, this simple rule will not suffice to verify that flows obey Kirchhoff's Laws.

CONSTRAINED DAY-AHEAD DISPATCH



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

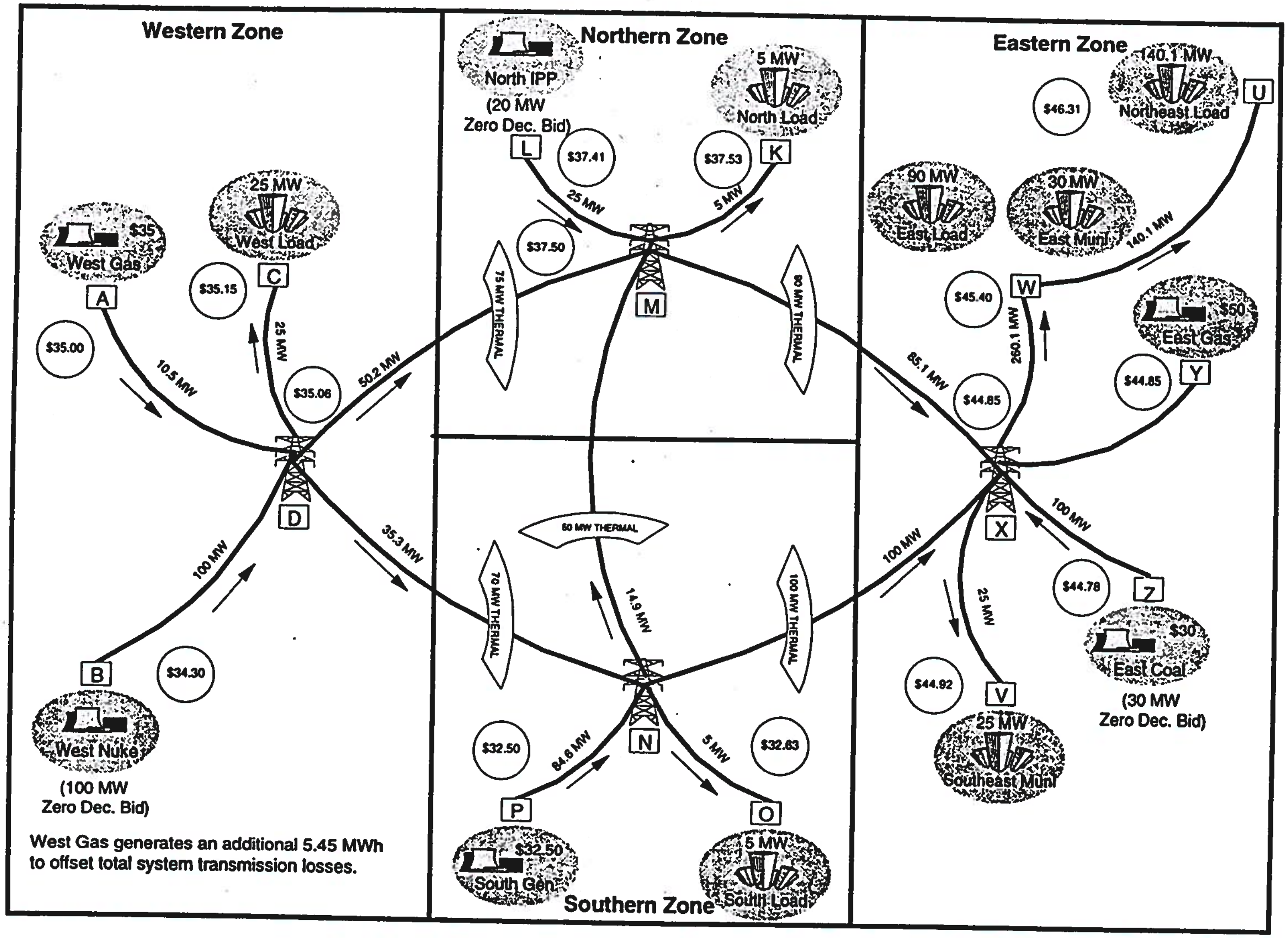
Exhibit 2B: Explanation for Calculation of LBMPs

Pope Testimony

CALCULATION OF LBMPs

The LBMP at each bus is the cost of supplying an incremental MWh of load at that bus. The cost of supplying the incremental load can be calculated as the change in the cost of the least-cost security-constrained dispatch that results from meeting the incremental load. In this example, the D-X line is the only contingency that must be monitored in performing this redispatch. If the redispatch is secure when the D-X line is lost, it will also be secure in the event of the loss of any other line.

INCREMENT OF LOAD AT BUS U



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

At Bus U, for example, an incremental 0.1 MWh of load would be met at least cost by a redispatch in which generation at West Gas increases by 0.5 MWh and generation at South Gen decreases by 0.4 MWh. In addition, generation at West Gas increases by another 0.004 MWh to offset incremental transmission losses caused by the increase in load. As shown in the figure above, this redispatch is feasible in the D-X contingency. Therefore, the LBMP at Bus U is the net cost of this redispatch, which is $4.632, or $46.32/MWh.[28]

DERIVATION OF LBMP AT BUS U

				Original Dispatch		Additional 0.1 MWh of Load at Bus U		Change	
Generators	At	Incremental/ Decremental Energy Bid ($/MWh)	Capacity (MW)	MWh	Total Bid Cost of Energy	MWh	Total Bid Cost of Energy	MWh	Total Bid Cost of Energy
West Gas	A	$35.00	100	15.445	$540.58	15.949	$558.22	0.504	$17.632
West Nuke	B	0.00	100	100.000	0.00	100.000	0.00	0	--
North IPP	L	30.00	5	5.000	150.00	5.000	150.00	0	--
North IPP		0.00	20	20.000	0.00	20.000	0.00	0	--
South Gen	P	32.50	100	85.000	2,762.50	84.600	2,749.50	-0.4	(13.000)
East Gas	Y	50.00	100	0.000	--	0.000	--	0	--
East Coal	Z	30.00	70	70.000	2,100.00	70.000	2,100.00	0	--
East Coal	Z	0.00	30	30.000	0.00	30.000	0.00	0	--
Total				325.445	$5,553.08	325.549	$5,707.72	0.104	$4.632

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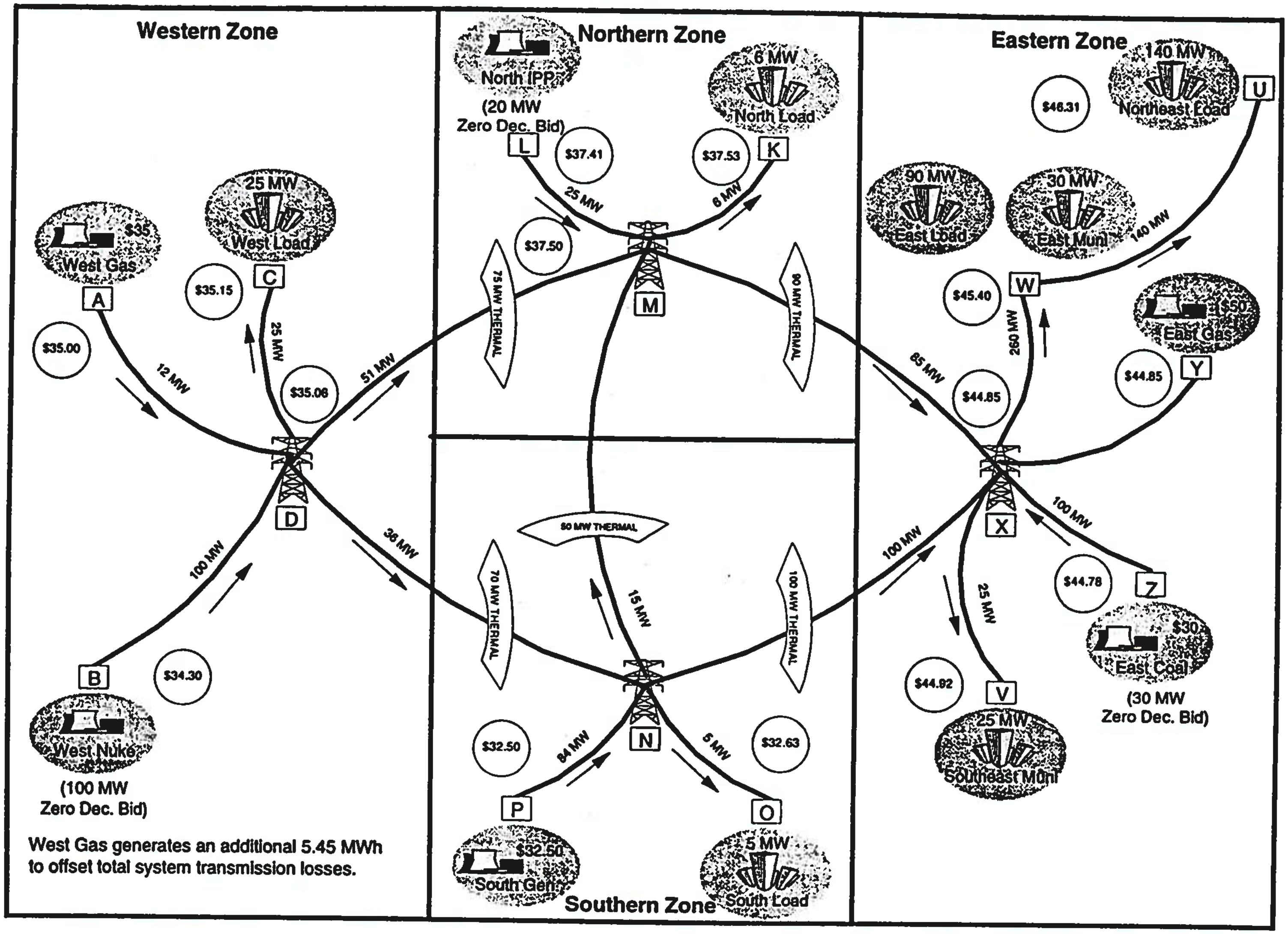
28 As transmission flows increase due to the introduction of an additional MWh of load on the system, marginal transmission losses also increase. The LBMP measures the cost per MWh of changing the system dispatch to meet an infinitesimal increase in load. The cost of meeting very small, but not infinitesimal, increases in load (such as 0.1 MWh) may be slightly higher due to the slight increase in marginal losses. Thus, the incremental cost of meeting 0.1 MWh of load alone is $4.632 (or $46.32/MWh), while the marginal cost of energy is $46.31/MWh for infinitesimal changes.

INCREMENT OF LOAD AT BUS K



Generator Capacities: West Nuke, 100 MW; West Gas, 100 MW; North IPP, 25 MW; South Gen, 100 MW; East Gas 100 MW; East Coal, 100 MW.

An incremental 1 MWh load at Bus K would be met by increasing generation at West Gas by 2.001 MWh and decreasing generation at South Gen by 1 MWh. Network interactions and the binding thermal constraints in the D-X contingency require the dispatch of both generators to be adjusted to meet the change in load (as in the corresponding example without losses); the introduction of losses causes the net increase in generation to slightly exceed the incremental 1 MWh of load at Bus K. The LBMP at Bus K is therefore the cost of the incremental generation at West Gas, $70.04, minus the cost of the reduction in generation at South Gen, $32.50, yielding a net cost of $37.54.[29]

DERIVATION OF LBMP AT BUS K

Generators	At	Incremental/ Decremental Energy Bid ($/MWh)	Capacity (MW)	Original Dispatch		Additional 1 MWh of Load at Bus K		Change	
				MWh	Total Bid Cost of Energy	MWh	Total Bid Cost of Energy	MWh	Total Bid Cost of Energy
West Gas	A	$35.00	100	15.445	$540.58	17.446	$610.61	2.001	$70.04
West Nuke	B	0.00	100	100.000	0.00	100.000	0.00	0	--
North IPP	L	30.00	5	5.000	150.00	5.000	150.00	0	--
North IPP		0.00	20	20.000	0.00	20.000	0.00	0	--
South Gen	P	32.50	100	85.000	2,762.50	84.000	2,730.00	-1	(32.50)
East Gas	Y	50.00	100	0.000	--	0.000	--	0	--
East Coal	Z	30.00	70	70.000	2,100.00	70.000	2,100.00	0	--
East Coal	Z	0.00	30	30.000	0.00	30.000	0.00	0	--
Total				325.445	$5,553.08	326.446	$5,740.61	1.001	$37.54

[29] See footnote on previous page.