

Report to
Hydro One Networks, Inc.

Regarding

A Jurisdictional Survey of Export and Wheel Through Service Rates

June 26, 2006

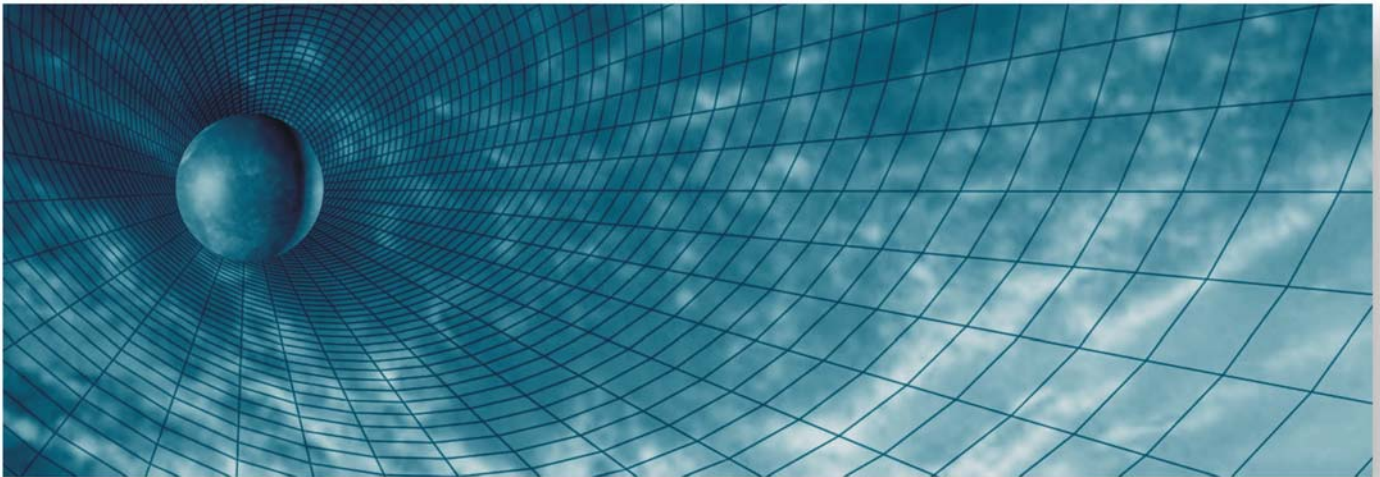


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SECTION I

EXECUTIVE SUMMARY

R.J. Rudden Associates (Rudden) was engaged by Hydro One Networks, Inc. (Hydro One) to perform a factual study (Study) regarding Point-to-Point (PTP) transmission service and rates used for determining the rates applicable to Export and Wheel Through Transactions (EWT) from and through the transmission system in jurisdictions neighboring Ontario. This Report presents the findings of our Study.

The Study covered five Transmission Providers jurisdictions in the United States and Canada. The majority of the data were obtained from Open Access Transmission Tariffs (OATTs) (i.e., rate schedules, revenue requirements, and load data) or from the jurisdictions' web sites. Some of the data pertaining to discounting provisions were obtained during direct interviews with the Transmission Providers' employees.

The table below summarizes the effective rates in each jurisdiction for Firm PTP transmission service rates that are utilized to provide EWT services. Also, the footnotes listed below the table identify various "adders" (additions to posted rates) that are applied in some jurisdictions. As one reviews the rates, it is important to note that \$/kW rates are capacity-type tariffs (PJM, ISO-NE, MISO, TransEnergy) and \$/MWh's are consumption-type tariffs. A capacity-type tariff cannot be converted to a consumption-type tariff.

Background

Evolution of Network Service and Point-to-Point (EWT) Service

Pursuant to FERC Order 2000, several ISOs have been formed for the purposes of ensuring equal access to transmission service, improving the long-term planning process for transmission infrastructure and fostering wholesale electricity transactions.

The last was to be accomplished, in part, by eliminating "rate pancaking". In the past, when electricity was injected at one point and withdrawn at another point, each transmission owner along the "path" was entitled to collect a transmission service fee. This made it costly to move electricity between control areas or zones, especially over longer distances.

As a result of rate pancaking, consumers in control areas where electricity had to be imported paid higher prices for electricity, because it was usually cheaper for load serving utilities to supply energy from local but inefficient generators, than from distant but more efficient generators (or from generators with available capacity). When wholesale transactions were necessitated due to local generation capacity constraints, consumers in the import areas had to pay all the transmission service fees along the path.

The formation of ISOs eliminated rate pancaking for transactions within ISOs. For transactions entirely within an ISO (i.e., generator and load are located in the ISO and in the same zone, or generator and load are both located in the ISO but in different zones) usually only a single transmission service fee is charged. Typically, these intra-ISO transactions are scheduled as Network Service, where load pays a fixed annual Network Service fee for a first-priority, unlimited right (subject to physical constraints) to transmit electricity between designated network

resources and network loads. Sometimes these transactions are scheduled as Point-to-Point transactions.

The formation of ISOs also reduced, but did not eliminate, rate pancaking for EWT transactions. For export transactions (i.e., the generator is located inside the ISO and the load outside) and wheel through transactions (i.e., both generator and load are located outside the ISO but the transaction “path” traverses the ISO), as well as for import transactions (i.e., the generator is located outside the ISO and the load inside), a single transmission service fee is paid to each ISO along the path. However, these transactions are still subject to rate pancaking on a smaller scale in that a transmission service fee may be required for each ISO along the transaction path. Typically, these transactions are scheduled as Point-to-Point, or EWT, transactions.

Changes in tariff design due to both the formation of ISOs and the elimination of seams costs have created winners and losers. Several mechanisms have been created to compensate the ratepayers that have lost revenue for a limited “transitional” time period.

While rate pancaking for intra-ISO transactions has been eliminated and rate pancaking for inter-ISO transactions has been reduced, greatly facilitating wholesale electricity transactions, the FERC has decided to facilitate wholesale electricity transactions further. Therefore, in a decision effective November 1, 2003, the FERC ordered PJM and MISO to eliminate rate pancaking on transactions between the two ISOs. Effective December 1, 2004, PJM eliminated transmission service fees on export transactions where the load is located in MISO; and MISO eliminated its Regional Through and Out Rate transmission (RTOR) transmission service fees on export transactions where the load is located in PJM. In addition, MISO eliminated its RTOR surcharge which was to have expired January 1, 2008 and had been implemented to compensate transmission owners for lost revenue due to the elimination of rate pancaking. Similarly, from December 1, 2004 through March 31, 2006, customers using PJM’s Network Service paid Seams Elimination Cost Assignment (SECA) Charges as defined by the PJM OATT.

The charges for EWT transactions between the NYISO and ISO-NE have been eliminated. The NYISO tariff states that the Transmission Service Charge is eliminated on all Exports and Wheel-Through Transactions scheduled with the NYISO to destinations within the New England Control Area (NECA). The ISO-NE tariff states that the Through or Out rate for any Through or Out Service transaction that (a) goes through or out of the NECA and (b) has the New England/NYCA boundary as its Point of Delivery is zero.

The NYISO has been working on the resolution of Northeast ISO Seams issues since 2003. As of December 2005, while Eliminating Rate Pancaking has been identified as an issue, there was no stakeholder-approved project. The NYISO, with the support of the New York TOs, intends to initiate discussions among the affected parties in the Northeast to explore the potential for rate pancaking relief between New York and PJM, and has initiated discussions with the Independent Electricity Operator (IESO) of Ontario to eliminate export fees.

Transmission Tariff Design for Network Rates and Point-to-Point (EWT) Rates

Presently, the typical tariff design for U.S. and Canadian transmission owners is that the Network Service rate is designed to recover the transmission owner’s annual net revenue requirement, which is computed as the annual gross revenue requirement less revenue from EWT transactions. EWT rates are computed for various terms of service (e.g., one month, one week, one day, one hour) by unitizing the annual gross revenue requirement (i.e., dividing by the MW in the peak hour), and dividing the result by the appropriate portion of a year (e.g., dividing by 12 to obtain the monthly rate).

The revenue from transmission service fees benefit the transmission owners' rate payers or shareholders. Some rate payers and shareholders benefited from the elimination of rate pancaking because they were net importers, and some were harmed because they lost revenue which was previously credited against the transmission owners' revenue requirement.

Summary of Firm Point-to-Point Transmission Service Rates

The effective rates shown below (in US\$) cover transmission infrastructure charges, and these rates exclude various adjustments that may be made in some jurisdictions to reflect congestion management and/or other jurisdiction-specific considerations.

SUMMARY OF FIRM POINT-TO-POINT TRANSMISSION SERVICE RATES						
	YEARLY SERVICE \$/kW-Yr	MONTHLY SERVICE \$/kW-Mon	WEEKLY SERVICE \$/kW-Wk	DAILY ON-PEAK SERVICE \$/kW-Day	DAILY OFF-PEAK SERVICE \$/kW-Day	COST FOR 100 MW CAPACITY FOR ONE DAY
PJM ¹	\$18.888	\$1.574	\$0.3632	\$0.0726	\$0.0519	\$7,260
ISO-NE	20.32	1.69	0.39	55.68 per MW-day		5,568
MISO ²	19.39	1.62	0.37	0.075	0.053	7,500
TransEnergie	61.97	5.17	1.19	0.24		24,000
NYISO ³	The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between \$3.7441 per MWh to \$8.1405 per MWh.					8,986-19,537
HydroOne	Energy-based is C\$1/ MWh, or US\$0.85 / MWh.					2,040

Notes:

- 1- Current Demand charge border rates for Firm Point-to-Point Transmission Service. An Expansion Cost Recovery Charge (ECRC) of \$0.007/MWh of energy delivered by customers to load in ComEd, AEP and Dayton transmission zones. This rate will change as a result of a FERC settlement Order issued May 30, 2006. Refer to the PJM section on ECRC for further details.
- 2- The MISO Regional Through and Out Rate ("RTOR"), applicable to transactions going out¹ or through² the MISO system, was in addition to all other charges in the Tariff. The RTOR expires January 31, 2008, but pursuant to FERC order, RTOR charges for exports to PJM were eliminated December 1, 2004. Further details are provided in the MISO section.

¹ Out Transmission Service means service where the source is in Control Areas inside the ISO Transmission System and the sink is in Control Areas outside the ISO Transmission System.

² Through Transmission Service means service where the source and the sink are in Control Areas outside of the ISO Transmission System.

- 3- In NYISO, an adder of, for example \$0.66 to \$2.190/MWhr (from Transmission Service Charge (TSC) Rates and NTAC, May 2006) also applies to the PTP service to provide for New York Power Authority transmission revenue requirement.

Non-Firm PTP service is also available in each of these ISOs. This Non-Firm service is available on a Monthly, Weekly, Daily, and Hourly basis. The primary difference between the Firm and Non-Firm services is that, the Non-Firm service can be recalled by the ISO any time (at its discretion) for example, to relieve congestion. All ISOs studied in this review revealed the main difference between Firm and Non-Firm services is a willingness to pay congestion charges if one takes Firm service. The nominal rates for the Non-Firm PTP service are generally similar or identical to the corresponding rates for the Firm PTP for the same duration; however, the ISO may offer discounts on these nominal rates. A review of discounts offered indicates that such discounting occurs infrequently and is not prevalent in most ISO's.

Summary of Point-to-Point Transmission Service Characteristics

PJM- PJM uses the FERC model for PTP Service. Service is offered for various terms for Firm Service and for Non-Firm Service. Pricing is based on Reserved Capacity, and the rates are derived from the annual gross revenue requirement for the zone where the load is located.

NYISO- NYISO PTP Service is also available for various terms, however pricing is based on MWh (energy flows) not on capacity. Rates are based on the annual gross revenue requirement for the zone where the load is located.

ISO New England- ISO New England PTP Service is charged based on Reserved Capacity. Rates are derived from the Pooled Transmission Facilities (PTF) Rate, which is the rate applicable to transmission facilities that are not regional. The ISO-NE regional transmission facility are somewhat analogous to zonal rates in other ISOs.

Midwest ISO- Midwest ISO PTP Service is based on the FERC model, although there are differences in the way the rate is computed for certain zones. Service is offered for various terms for Firm Service and for Non-Firm Service. Pricing is based on Reserved Capacity, and the rates are derived from the annual gross revenue requirement for the zone where the load is located.

TransEnergie- TransEnergie also uses the FERC model for PTP Service. Service is offered for various terms for Firm Service and for Non-Firm Service. Pricing is based on Reserved Capacity, and the rate (there is only one rate) is derived from the annual gross revenue requirement.

Export Transactions for All ISOs - Considering the direction that FERC policy is heading concerning the eventual elimination of seams issues, one may expect that for all of the ISOs in this Study, transmission service fees for export transactions may reasonably be anticipated to be eliminated in the long term.

Other Information

In PJM, the transmission customer purchasing Firm PTP service also gets the corresponding Financial Transmission Rights (FTR) (obligations) to hedge against potential transmission congestion costs arising out of Locational Marginal Pricing (LMP) in the energy market.

In all ISOs, Rudden was unable to gain access to frequencies and amounts of discounts. This data is not available to the general public. The requirements to post available discounts on OASIS are consistent over most ISOs. A general perception of phone interviews revealed that discounts are quite rare. However, Rudden was unable to uncover any evidence to support this assertion.

The table below provides a summary of key size and scope statistics for the entities studied.

KEY SIZE AND SCOPE STATISTICS						
	UNITS	PJM	ISO-NE	MISO	TRANS-ENERGIE	NYISO
Generating sources	#	1,082	350	5,091	54	335
Generating capacity (nominal)	MW	164,634	31,000	140,606	34,571	37,524
Peak demand	MW	134,017	26,885	112,197	33,636	33,295
Transmission lines	miles	56,070	8,000	97,000	20,221	10,775
States / Provinces served	#	14	6	16	1	2
Population (customers) served	MM	51	14	16	8	19
Area served	000 sq mi	164	63	947	595	48
Market Participants	#	Over 390	Over 300	Over 200		Over 300

SECTION II

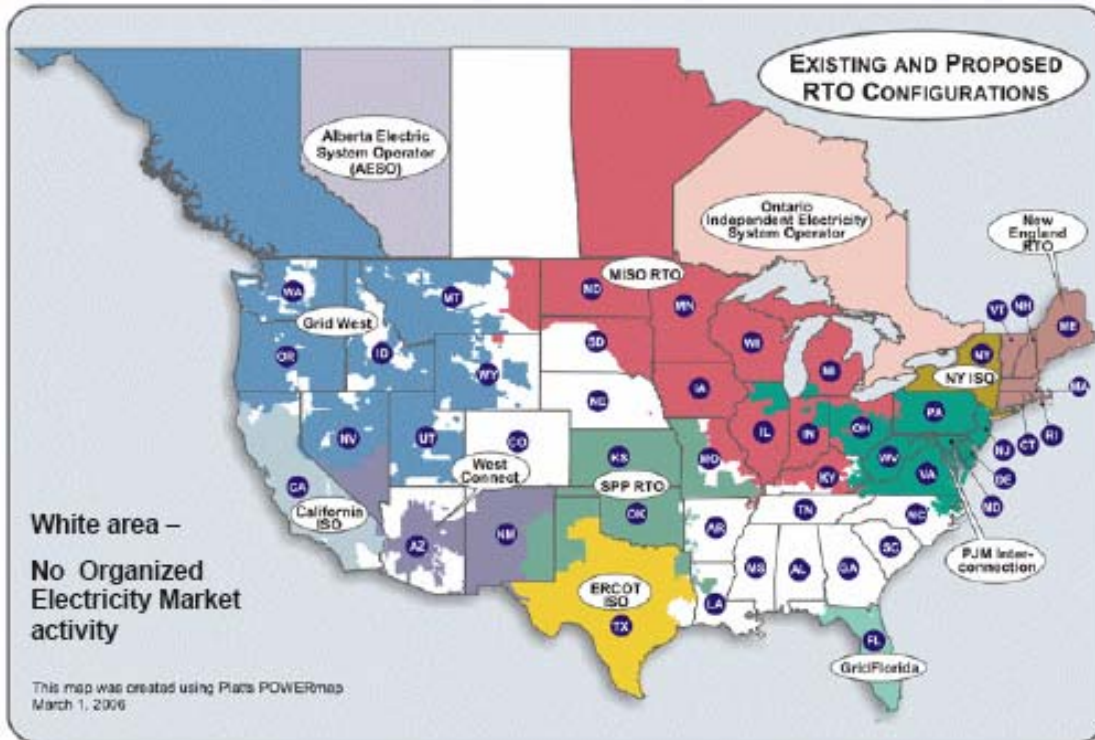
INTRODUCTION

Hydro One is in the process of developing a submission to the Ontario Energy Board for setting transmission rates applicable in Ontario. Rudden has performed this Study in order to provide a set of factual data pertaining to electricity transmission rates and related information with respect to EWT transactions in electricity transmission systems of selected electricity transmission providers around Ontario.

TRANSMISSION PROVIDERS BEING STUDIED

- The PJM Interconnection (PJM)
- The New York Independent System Operator (NYISO)
- The Independent System Operator of New England (ISO-NE)
- The Midwest Independent System Operator (Midwest ISO), including the province of Manitoba
- TransEnergie (the transmission affiliate of Hydro Quebec)

The following map³ shows the geographical scope of these entities.



³ Source, FERC

SCOPE OF THE STUDY

The purpose of this Report is to provide Hydro One with data and relevant information about transmission rates that are levied for EWT service transactions in the transmission systems mentioned above. The essential details developed for each jurisdiction include the following:

- General discussion of transmission services offered by region.
- Total demand (average or sum of twelve monthly demands) in the Transmission Company or Transmission Rate Zone that has been used to derive the monthly Network Service rate to collect transmission owner's revenue requirement.
- Rates for the provision of firm EWT transmission service, including applicable charge determinants and duration, and a brief description of the method used to derive EWT Service Rates from the rates for the individual Transmission Companies or Transmission Rate Zones.
- Rate surcharge adders that may be applicable for a transition period or permanently, in addition to the nominal EWT service rates in the jurisdictions, and a brief description explaining how the revenue from such adders is distributed among the transmitters.
- Discounting provisions, if applicable, to EWT Service Rates if and when transmission customers wish to utilize non-firm EWT Service, and brief description concerning which entity has the accountability to determine / revise applicable discounts on a day to day basis, and key commercial terms which distinguish firm and non-firm service.
- If available, data pertaining to approximate frequency and extent of actual discounts offered for the EWT Service during any three to six month period. If possible, the periods chosen should be similar for all Jurisdictions so as to provide a meaningful comparison.
- Any FTRs or PTRs or FGRs that are inherent in the purchase of the EWT Service. In case these rights are included, a brief description was provided concerning options or obligations associated with these rights and the method of calculating the credits associated with these rights.
- A discussion of evolving rules and recent RTO developments and or regulatory developments affecting the Transmission Providers in the Study.

All rates in this Report are presented in \$US. Rates stated in the tariffs at Canadian are so indicated, and were converted in this report at \$C1.00 = US\$0.85.

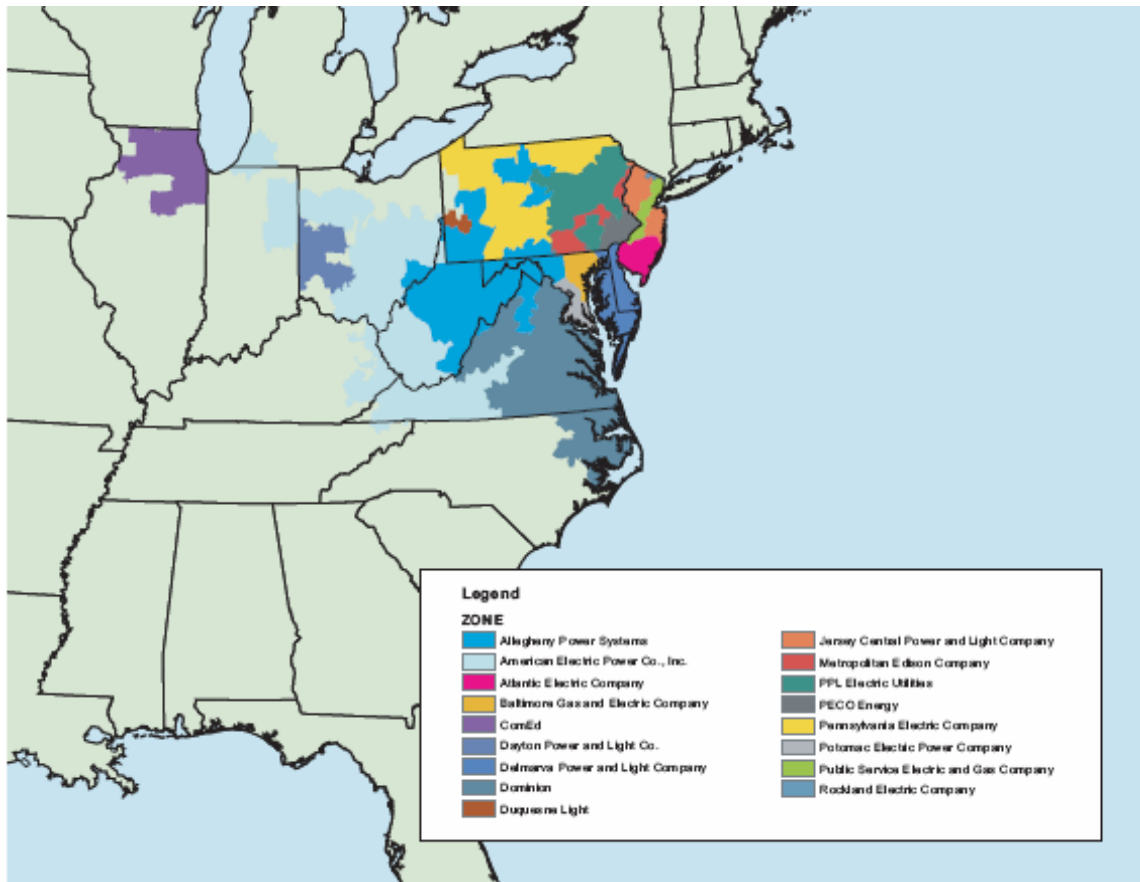
SECTION III

PJM INTERCONNECTION, LLC (PJM)

PJM administers the largest, centrally dispatched Control Area in North America. It coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania and Tennessee, Virginia, West Virginia and the District of Columbia.

The scope of PJM’s operations is extensive and it has experienced substantial recent growth due to the additions of Transmission owners in Illinois, Indiana, Kentucky, Michigan, North Carolina and Tennessee to the PJM system.

The following map illustrates the geographic areas included in PJM.



General Description of Transmission Services.

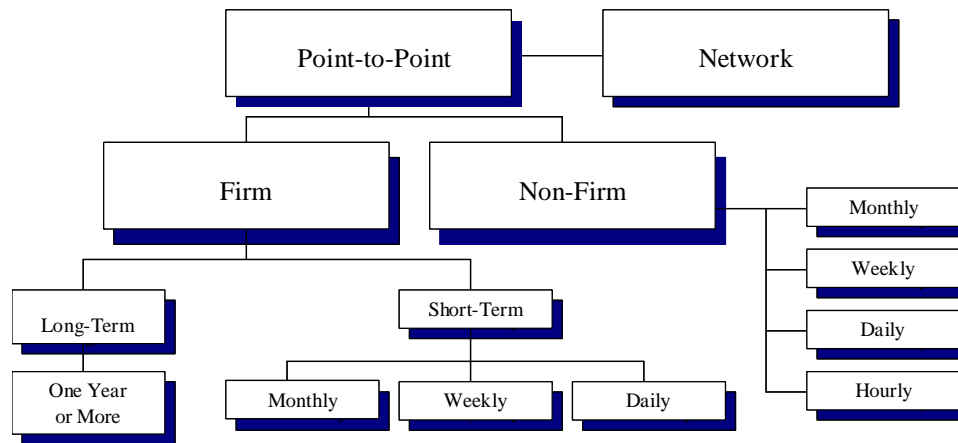
PJM offers Network Integration Transmission Service (Network Service) and PTP Transmission Service (PTP Service) to market participants.

Customers taking Network Service are entitled to utilize network resources (as defined in the PJM OATT) for serving load within the PJM Control Area, by providing for the transfer of electricity from network resources or from PJM spot market resources to network load. Network resources and network load that qualify for Network Service are located within the PJM Control Area. Network Service is available on a subscription basis; that is, the customer does not need to pay separately for each use of the network. Further information on Network Service is available at www.PJM.com, (PJM OATT, PJM User Manuals, etc).

Customers that purchase PTP transmission service are entitled to transfer electricity from a specified Point of Receipt (POR) to a specified Point of Delivery (POD) into, from, or through the PJM Control Area. Both Firm and Non-Firm PTP Service are available for specific needs. PTP Service requests are made through OASIS (Open Access Same Time Information System).

The transmission services available to eligible customers are listed in the PJM Control Area OATT. Customers make requests to the PJM for the desired transmission services. PJM evaluates each transmission service request for impact to the system and approves or denies the request for the transmission service.

The chart below shows the transmission services available for the PJM Control Area.



Transmission Pricing and Rate Design

The rate design in PJM is based on applying a Network Service rate for transmission service entirely within PJM and a PTP Service rate for Export and Wheel-Through (EWT) service.

Firm PTP Transmission Service

In PJM, EWT service includes Long-Term Firm PTP Service, Short-Term Firm PTP Service and Non-Firm PTP Service, and is provided for time periods of varying duration. EWT service differs from Network Service in that

EWT service is for a specified POD and a specified POR. PTP Service can be used for the transmission of energy (or availability of capacity) into, out of or through the PJM Control Area.

Firm transmission service is obtained by requesting to reserve capacity for a specified POD and a specified POR. The minimum term of Long-Term Firm PTP Service is one year. Short-Term Firm PTP Service is for one day, one week or one month. The customer may then request to schedule transactions, up to the amount of capacity reserved, for the specified POD and POR. The maximum term of Firm PTP Service is determined based upon available transfer capability for future periods and is specified. In scheduling transactions, Firm PTP Service has priority over Non-Firm PTP Service. The charge for Firm PTP Service is based on the reserved capacity and not on actual usage.

Firm PTP Service that is used to serve load located outside the PJM Control Area is charged for PTP Service at a single rate (Border Rate) based on the weighted average of the zonal Network Service rates for all PJM zones. Firm PTP Service that is used to serve load within the PJM Control Area is charged at the zonal PTP rate where the load is located. Zonal PTP rates are derived from the zonal Network Service rate and vary based on the period for which the service is needed. Customers may choose to use PTP Service instead of Network Service for transactions entirely within PJM, but for most customers this will result in paying more than for Network Service.

The maximum Firm PTP Service demand charge to a customer for a week (Monday through Sunday) is the weekly Firm PTP Service rate times the highest amount of Reserve Capacity in any day during that week.

Effective December 1, 2004, there is no charge for Firm PTP Service with a POD at a Midwest ISO interface as mandated by FERC.

The table below presents the rates for Long-Term Firm and Short-Term Firm PTP Transmission Service from Schedule 7 of the PJM OATT, and also shows, in the columns “Hourly On-Peak Service” and “Hourly Off-Peak Service”, the rates for Non-Firm PTP Transmission Service from Schedule 8 of the PJM OATT.

PJM Long-Term Firm, Short-Term Firm and Non-Firm PTP Transmission Service							
ZONE	YEARLY SERVICE \$/kW-Yr	MONTHLY SERVICE \$/kW-Month	WEEKLY SERVICE \$/kW-Wk	DAILY ON-PEAK SERVICE \$/kW-Day	DAILY OFF-PEAK SERVICE \$/kW-Day	HOURLY ON-PEAK SERVICE \$/MWh	HOURLY OFF-PEAK SERVICE \$/MWh
PJM Border	18.888	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE	23.809	1.984	0.4580	0.0920	0.0650	5.70	2.72
BG&E	15.675	1.306	0.3010	0.0600	0.0430	3.80	1.80
Delmarva	19.378	1.615	0.3730	0.0750	0.0530	4.60	2.21
JCPL	15.112	1.259	0.2906	0.0581	0.0414	3.60	1.73
MetEd	15.112	1.259	0.2906	0.0581	0.0414	3.60	1.73
Penelec	15.112	1.259	0.2906	0.0581	0.0414	3.60	1.73
PECO	26.264	2.189	0.5051	0.1010	0.0722	6.30	3.01

PJM Long-Term Firm, Short-Term Firm and Non-Firm PTP Transmission Service							
ZONE	YEARLY SERVICE \$/kW-Yr	MONTHLY SERVICE \$/kW-Month	WEEKLY SERVICE \$/kW-Wk	DAILY ON-PEAK SERVICE \$/kW-Day	DAILY OFF-PEAK SERVICE \$/kW-Day	HOURLY ON-PEAK SERVICE \$/MWh	HOURLY OFF-PEAK SERVICE \$/MWh
PPL	22.507	1.876	0.4328	0.0866	0.0618	5.40	2.58
Pepco	20.999	1.750	0.4040	0.0810	0.0580	5.00	2.40
PSE&G	23.696	1.975	0.4557	0.0911	0.0651	5.70	2.71
AP	20.847	1.737	0.4009	0.0802	0.0573	5.00	2.39
Rockland	32.114	2.676	0.6176	0.1235	0.0882	7.70	3.67
ComEd	12.201	1.017	0.2346	0.0469	0.0334	2.90	1.39
AEP: 1-Nov-05	12.97272	1.08106	0.24948	0.0499	0.03564	3.12	2.08
SECA Ended	19.4568	1.6214	0.37417	0.07483	0.05345	4.68	3.12
W-JF Line In	21.0888	1.7574	0.40555	0.08111	0.05794	5.67	5.38
Dayton	15.674	1.306	0.3014	0.0603	0.0431	3.37	1.79
Duquesne	14.17	1.18	0.27	0.054	0.0389	3.08	1.61
Dominion	12.79297	1.06608	0.24602	0.0492	0.03505	3.38	1.46

Non-Firm PTP Transmission Service

Non-Firm PTP transmission service is available from transmission capability in excess of that needed for reliable service to native load customers, Network Service customers and customers taking Long-Term and Short-Term Firm PTP Service. Non-Firm PTP Service must be reserved and scheduled between a specified POR and a specified POD. Non-Firm PTP Service is available for periods ranging from one hour to one month. Non-Firm PTP Service must be reserved, but scheduled transactions have lower priority than Firm PTP Service transactions.

The Non-Firm PTP Service rates are the same as the Firm PTP Service rates, except that Non-Firm PTP Service also available at an hourly rate. For hourly transactions, Non-Firm PTP Service charges are computed for each hour and collected monthly, based on the sum of the hourly calculations. The charges are equal to the hourly reserved capacity less curtailed transactions, times the hourly Non-Firm PTP rate stated in \$ / MWh. The table above presents the rates for Non-Firm PTP Transmission Service in the columns "Hourly On-Peak Service" and "Hourly Off-Peak Service".

Non-Firm PTP Service that is used to serve load outside the PJM Control Area (POD is PJM Border) is charged at discounted rate of \$0.67 / MWh for hourly service. In addition, effective December 1, 2004, there is no charge for Non-Firm PTP Service with a POD at a Midwest ISO interface as mandated by FERC.

The maximum Non-Firm PTP Service demand charge to a customer for a week (Monday through Sunday) is the weekly Non-Firm PTP Service rate times the highest amount of Reserve Capacity in any day during that week.

Distribution of Revenues from Non-Firm Point-to-Point Transmission Service

Distribution of Transmission revenues from Non-Firm PTP Service (other than the portion of such revenues equal to congestion charges and the revenues attributable to the transitional revenue neutrality charge) for a billing month are distributed to Network Service customers (including Transmission Owners to the extent that they are representing their bundled retail customers) and Firm PTP Service customers in proportion to their demand charges (including any imputed demand charges for bundled service to native load customers) for Network Service and their charges for reserved capacity for Firm PTP Service.

Rate Surcharge Adders Applicable to PTP Transmission Service:

This section lists all the charges identified in the various PJM agreements, and describes in detail the present rate surcharge adders. The adders are: Expansion Cost Recovery charge, Mid-Atlantic Area Council charge, FERC Annual Fee Recovery charge, Organization of PJM States, Inc (OPSI) Funding charge, Transmission Enhancement charge and RTO start-up cost recovery.

Expansion Cost Recovery Charge (ECRC)

The ECRC identified in the current Schedule 13 of the OATT is for the recovery of costs related to the expansion of the PJM markets and system operations through integration of new transmission zones into PJM, and the relative rate savings to the Pre-existing PJM Zones under Schedule 9 of the OATT. Load Serving Entities (LSEs) using Point-to-Point and Network Integration Transmission Service pay an ECRC.

PJM will charge each customer using Point-to-Point or Network Integration Transmission Service each month a charge equal to \$0.007 times the total quantity in MWhs of energy delivered to load (net of operating Behind the Meter Generation, but not to be less than zero) in the PJM Region.

PJM distributes revenues collected under this schedule each calendar month to American Electric Power (AEP), Commonwealth Edison Company (ComEd), and The Dayton Power and Light Company (Dayton) in proportion to the expansion costs included for recovery for such Transmission Owner as follows:

Company	ECRC Allocation
American Electric Power	48.35%
Commonwealth Edison Company	43.37%
The Dayton Power and Light Company	8.28%

The charge provided for under this Schedule 13 shall terminate effective on the day on which the sum total of the revenues collected under this charge equals \$43,765,569.

The ECRC charges described above will be modified as a result of a FERC Order issued on May 30, 2006⁴ approving an uncontested settlement involving AEP, ComEd and Dayton,

⁴ FERC Order “Approving Uncontested Settlement” May 30, 2006, Docket Nos. EL05-74-001 and 002

The Settlement is intended to resolve all issues in this proceeding, which concerns the funding of certain non-capital costs associated with the integration of AEP, ComEd and Dayton into PJM Interconnection, L.L.C. (PJM). Pursuant to the Settlement, these costs are now established at \$52,549,556, effective May 1, 2005 and are to be recovered over approximately ten years.

PJM has been ordered to make the refunds, or assess surcharges, as necessary to reflect the rates provided in the Settlement. PJM will file with the Commission a refund report within thirty (30) days of the date on which PJM has provided refunds to all customers, as described in the Settlement.

While PJM must begin to provide refunds beginning June 1, 2006, it has not yet revised Schedule 13. Based on discussions with PJM staff, it is our understanding that among the changes being made include switching from a per MWh rate to a peak load determination.

FERC Annual Charge Recovery

PJM as a public utility and the Transmission Provider its Tariff is subject to annual charges assessed by FERC in accordance with Part 382 of FERC's regulations. Schedule 9-FERC of the OATT recovers PJM's payments to FERC for the FERC annual charge. FERC assesses its annual charge to PJM and other public utilities based on their total megawatt-hours of transmission of electric energy in interstate commerce. Accordingly, the charges under this Schedule are assessed on all megawatt-hours of transmission provided by PJM. PJM provides this service to customers using Point-to-Point and Network Integration Transmission Service under this Tariff.

PJM charges each user of this service each month, a charge equal to the FERC Charge Recovery Rate defined below times the total quantity in MWhs of energy delivered during such month by such user as a transmission customer under this Tariff for Point-to-Point Transmission Service or Network Integration Transmission Service.

The FERC Charge Recovery Rate ("FCRR") is calculated each year in accordance with the formula:

$$\text{FCRR} = (\text{CYFC} + (\text{FCPY} - \text{FCRPY})) / \text{PJMTHTU}$$

Where:

FCRR is the FERC Charge Recovery Rate

CYFC, Current Year FERC Charges, are the costs PJM estimates for FERC Annual Charges related to the year for which FCRR is being calculated, which may include prorated portions of multiple FERC fiscal years.

FCPY, FERC charge prior year, is the amount invoiced by FERC and paid by PJM for FERC annual charges in the year immediately preceding the year for which FCRR is being calculated.

FCRPY, FERC charge actual recovery prior year, is the amount billed Schedule 9-FERC for the year immediately preceding the year for which FCRR is being calculated.

PJMTHTU, PJM total hourly transmission usage, is the estimated total quantity in MWhs of energy to be delivered under Point-to-Point or Network Integration Transmission Service by all customers during the year for which FCRR is being calculated.

Organization of PJM States, Inc (OPSI) Funding Charge

The Organization of PJM States, Inc. is funded pursuant to Schedule 9-OPSI of the OATT. The OPSI charge under Schedule 9-OPSI, is assessed on all megawatt-hours of transmission provided by PJM. PJM provides this service to customers using Point-to-Point and Network Integration Transmission Service under the OATT.

PJM charges each user each month a charge equal to the OPSI Funding Rate (“OFR”) times the total quantity in MWhs of energy delivered during such month by such user as a transmission customer under this Tariff.

PJM submitted to the FERC for review and approval the OPSI budget for calendar year 2006, an amount totaling \$425,000. Each year thereafter, OPSI shall submit to the PJM finance committee an annual budget for the next calendar year no later than June 1st. The OPSI Board will receive comments from the PJM finance committee for consideration until September 1st. OPSI shall submit its final annual budget for the next calendar year to PJM no later than September 30th. PJM shall submit such annual budget to the FERC for information (except where such annual budget includes an increase of greater than fifteen percent above the budget on file for the current calendar year, in which case PJM shall submit the budget to the FERC for review and approval), and post the next calendar year’s OPSI budget and resulting OFR on the PJM internet site, no later than October 31st.

Mid-Atlantic Area Council Charge

The Transmission Provider shall recover the costs of MAAC from Transmission Customers delivering energy to load in the MAAC Control Zone under Schedule 10 of the OATT.

MAAC is one of the regional reliability councils of NERC. MAAC’s purpose is to ensure the reliability of the interconnected bulk power system in the MAAC region, which is coextensive with the MAAC Control Zone. The monthly costs and expenses of MAAC shall be allocated and billed to Transmission Customers in the same proportions that each Transmission Customer’s use in the MAAC Control Zone of the Transmission System, on a megawatt hour basis, bears to the total of such use in the MAAC Control Zone by all customers in the same month, as follows:

$$\text{Monthly Charge} = \text{MAAC Monthly Expense} * \text{Customer Allocation}$$

Where:

MAAC Monthly Expense is the monthly costs and expenses of MAAC; and Customer Allocation is the monthly transmission use in the MAAC Control Zone of the Transmission Customer divided by the total transmission use in the MAAC Control Zone, i.e., the actual total quantity in MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the MAAC Control Zone under Point-to-Point or Network Integration Transmission Service by all customers during the month for which the monthly charge is being calculated.

Transmission Enhancement Charges

The Transmission Provider shall collect from designated customers using Point-to-Point Transmission Service and Network Integration Transmission Service the charges of Transmission Owners related to the costs of Required Transmission Enhancements under Schedule 12 of the OATT,

One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (“Coordinated System Plan”). Section 1.7 of Schedule 6 of the Operating Agreement recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates Transmission Provider to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion Plan or the Coordinated System Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

1. Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;
2. Make a filing pursuant Section 205 of the Federal Power Act and the FERC’s rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or
3. Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

RTO Start-up Cost Recovery

Commonwealth Edison Company (ComEd) - In addition to other PTP transmission service rates set forth in Schedule 7 of the OATT, pursuant to FERC’s Order⁵ and the Settlement Agreement in that same docket, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four Decimal places:

Annual Rate - \$/kW/year = \$1,253,787, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - \$/kW/month. = Annual Rate divided by 12;

Weekly Rate - \$/kW/week = Annual Rate divided by 52;

Daily Rate - \$/kW/day = Weekly Rate divided by 5.

⁵ FERC’s November 10, 2003 Order in Docket No. ER03-1335 (Commonwealth Edison Company, 105 FERC ¶ 61,186 (2003))

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2005-2014.

American Electric Power (AEP) - Pursuant to the Commission's Order Approving Settlement Agreement in Docket No. ER05-751, the rates in the PTP Transmission Service Schedule, for service in the AEP Zone, will be increased in three steps, as of the following effective dates: (1) November 1, 2005, (2) April 1, 2006 or the date that Seams Elimination Cost Allocation charges, pursuant to Docket Nos. EL04-135-000, et al, end, and (3) August 1, 2006 or the first day of the next calendar month after the Wyoming-Jacksons Ferry 765 kV transmission project enters service, if later. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - \$/kW/year = \$2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - \$/kW/month. = Annual Rate divided by 12;

Weekly Rate - \$/kW/week = Annual Rate divided by 52;

Daily Rate - \$/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be \$8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be \$8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2014.

Seams Elimination Cost Assignment (SECA) Charges

As of March 31, 2006, these charges are no longer in effect. The information concerning SECA charges is presented below to illustrate how they were handled by PJM.

Background: The Federal Energy Regulatory Commission⁶ approved a pricing structure to facilitate seamless trading of electricity between the Midwest Independent Transmission System Operator (Midwest ISO) and PJM Interconnection. The new pricing structure was effective December 1, 2004 and eliminated transmission rate "pancaking", in order to promote more efficient electricity flows between the two organizations. FERC Chairman Pat Wood III said, "This is another step forward in the steady, positive evolution of RTOs and competitive markets".

Specifically, the FERC "order conditionally accepts, for use during an initial fixed period ending January 31, 2008, the so-called "license plate" rate design proposed by a majority of the Midwest ISO and PJM transmission

⁶ FERC Press Release, 11/18/04, Docket Nos. ER05-6-000, et al. and ER04-375-007 "KEY RULING FURTHERS MIDWEST ISO, PJM INTEGRATION, PROPOSAL BOOSTS ELECTRIC MARKET EFFICIENCY"

owners, and rejects an offer of settlement filed with that proposal. The license plate rate design will be subject to re-evaluation after that fixed period. The license plate rate design accepted today, coupled with a transition mechanism and re-evaluation after a fixed period, represents a reasonable approach to pricing transmission service between the two RTOs upon the elimination of pancaked rates, and is consistent with previous pricing policies, the Commission said. License plate rates provide access to a regional transmission system at a single rate, although the rate may vary based on where the customer is located.”

To mitigate the lost revenue, from December 1, 2004 through March 31, 2006, customers using PJM’s Network Service paid Seams Elimination Cost Assignment (SECA) Charges as defined by the PJM OATT. The PJM accounting process calculates each customer’s SECA charges. The collected PJM/MISO SECA charges are then provided as credits to MISO and the collected Intra-PJM SECA charges are allocated in accordance with Attachment R of the PJM Open Access Transmission Tariff.

Seams Elimination Cost Assignment (SECA) Charges

- Each Network Integration Transmission Customer was billed each month a PJM/MISO SECA charge equal to the applicable zonal or subzonal monthly rate in Attachment X of the OATT to the PJM Open Access Transmission Tariff times its daily network service peak load contributions in that zone, averaged across all days in the month. Any charge refunds required for MISO “existing transaction” customers were provided (if this was included as billing adjustments on a one month lag, it included interest).
- Each Network Integration Transmission Customer was billed each month an Intra-PJM SECA charge equal to the applicable zonal or subzonal monthly rate in Attachment X to the PJM Open Access Transmission Tariff times its daily network service peak load contributions in that zone, averaged across all days in the month.
- Network Customers in the Duquesne Zone paid a fixed \$/month rate for January and February 2005 and a variable \$/MWh rate for March 2005 through March 2006 as described in Attachment X. The MWh of load used for this calculation was based on current month load responsibilities and then true-up based on reconciled load amounts two months after the fact.

Seams Elimination Cost Assignment (SECA) Credits

- PJM distributed all PJM/MISO SECA revenues collected from PJM Network Customers each calendar month as a credit to MISO.
- PJM distributed all PJM/MISO SECA revenues received from MISO each calendar month (less any refunds MISO provides to PJM “existing transaction” customers on a one-month lag) to PJM Transmission Owners in accordance with the applicable percentage shares contained in Attachment R to the OATT with ComEd’s share of revenues further allocated to ComEd network customers based on demand charge ratios.

- Each month, on a one-month lag, PJM provided negative PJM/MISO SECA credit adjustments (in the same proportions as described immediately above) in order to provide any SECA charge refunds required for MISO “existing e
- PJM distributed all Intra-PJM SECA revenues each calendar month to PJM Transmission Owners in accordance with the applicable percentage shares contained in Attachment R with ComEd’s share of revenues further allocated to ComEd network customers based on demand charge ratios.

Discounting Provisions related to EWT services:

In PJM, three principal requirements apply to discounts for transmission service as follows:

- (1) Any offer of a discount made by the transmission provider must be announced to all eligible customers solely by posting on the OASIS;
- (2) Any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an affiliate’s use) must occur solely by posting on the OASIS; and
- (3) Once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the transmission provider must offer the same discounted transmission service rate for the same time period to all eligible customers on all unconstrained transmission paths that go to the same point(s) of delivery on the transmission system.

Financial Transaction Rights:

In PJM, a Fixed Transmission Right (FTR)⁷ is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges (TCCs) that arise when the transmission grid is congested in the Day-Ahead Market and differences in Day-Ahead locational marginal pricing (LMPs) result from the dispatch of generators out of merit order to relieve the congestion. In the Monthly FTR Auctions, FTRs can be designated to and from any single bus, Hub, Zone, Aggregate or Interface bus for which PJM calculates and posts Day-ahead LMP values. In the Annual FTR Auction, valid sources and sinks are limited to hubs, zones, generator buses, aggregates and interface buses. Each FTR is defined from a POR to a POD.

For each hour in which congestion exists on the Transmission System between the PORs and PODs specified in the FTR, the holder of the FTR is awarded a share of the TCCs collected from the market participants.

Essentially, FTRs are financial instruments that entitle the holder to rebates of congestion charges paid by the Firm Transmission Service Customers. Thus, FTRs can be used to protect their holders from the cost of Transmission Congestion when their energy deliveries are consistent with their firm reservations. FTRs do not represent a right for physical delivery of power. The holder of the FTR is not required to deliver energy in order to receive a payment. The amount is paid to the FTR holders regardless of who delivered energy or the amount delivered across the path designated in the FTR.

⁷ PJM Manual #6 “Financial Transmission Rights”

The hourly economic value of an FTR is based on the FTR MW reservation and the difference between Day-ahead LMPs at the POD and the POR designated in the FTR. Therefore, it is important to note that an FTR can provide financial benefit, but it can also be a financial liability resulting in a charge to the holder.

Only PJM Members or a Transmission Customers can buy or sell FTRs in the PJM FTR Auctions, or in FTR secondary trading. However, anyone may buy and sell FTRs on the secondary market outside of eFTR; however, PJM Market Settlements makes the proper billing adjustments only for eFTR transactions. FTRs can be acquired using three market mechanisms, as follows.

1. Annual FTR Auction – PJM conducts an Annual FTR auction, in which the entire PJM transmission entitlement is offered on a long-term basis. The clearing mechanism of the Annual FTR Auction will maximize the quote-based value of FTRs awarded in the auction. Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the Annual FTR Auction are allocated.
2. Monthly FTR Auction – PJM conducts a Monthly FTRs auction, in which any residual transmission entitlements left over from the Annual FTR Auction are offered. The auction also allows Market Participants an opportunity to sell FTRs that they hold. Market Participants offer to sell or request to buy FTRs through an Internet computer application called eFTR.
3. Secondary Market - The FTR secondary market is a bilateral trading system that facilitates trading of existing FTRs between PJM Members through an Internet computer application called eFTR.

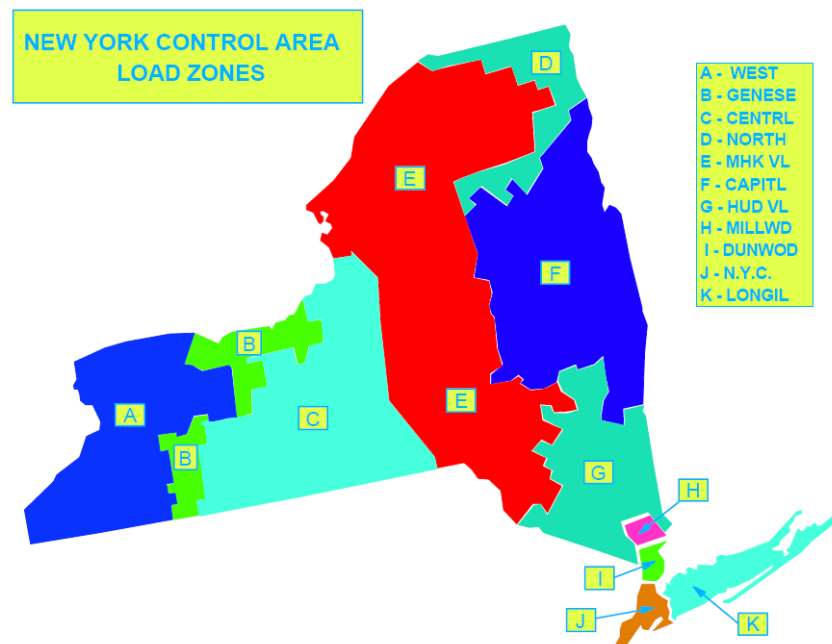
SECTION IV

NEW YORK INDEPENDENT SYSTEM OPERATOR (NYISO)

NYISO is responsible for maintaining the reliability and security of New York State's bulk power system (the New York Control Area or NYCA) and ensuring fair access to transmission facilities. It also acts as a power exchange for a competitive electric market, and operates a two-settlement spot energy market with locational marginal pricing (LMP), a regional and locational capacity market, and a financial transmission rights market.⁸

The system is bordered by and interconnected with the Hydro One (Ontario) and Hydro Quebec transmission systems along its Canadian borders, and PJM and ISO-NE systems along its United States borders. NYISO controls the entire transmission system of New York State.

The following map illustrates the NYISO Control area and zones.



The eight major Transmission owners are:

- Central Hudson Gas & Electric Company
- Consolidated Edison Company of New York, Inc.
- Long Island Power Authority (state owned and operated, generation and transmission company)
- New York Power Authority (NYPA) (state owned and operated, generation and transmission company)
- New York State Electric & Gas Corporation

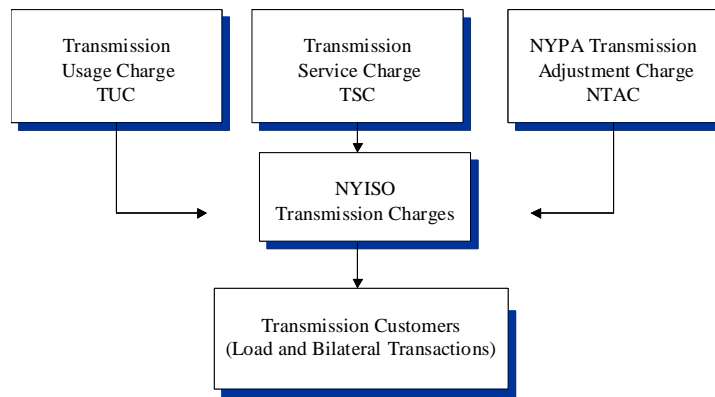
⁸ FERC State Of Markets Report 2004, June 2005

- Niagara Mohawk Power Company
- Orange and Rockland Utilities, Inc. (merged with Consolidated Edison in the summer of 1999)
- Rochester Gas and Electric Company

Transmission Pricing and Rate Design

In the NYISO, the Transmission Service Charge (TSC) is the basic charge for use of the NYISO-administered transmission system. The TSC is Transmission Owner-specific and ensures recovery of the Transmission Owner’s embedded costs as well as other items (discussed below). All wholesale loads that withdraw energy from the NYCA pay a TSC, including withdrawals for Export or Wheel-Through transactions.

The chart below describes the different elements that comprise the transmission charges in the NYISO:



NYISO Administers Two Tariffs

Under the OATT, NYISO supplies Network Integration Transmission Service (Network Service), Firm and Non-Firm PTP transmission service, and all necessary ancillary services. The NYISO also administers the Market Services Tariff to operate the Locational Based Marginal Prices (LBMP) market for energy and operating reserves, procure control services. The NYISO also administers the installed capacity requirement and the related ICAP market for the NYCA.

Because the TSC is computed based on MWh, there is no difference between Network Service and Point-to-Point service; effectively, all transactions are point-to-point. Transmission Owners do not pay themselves when providing bundled retail service entirely within their zones

Network and PTP Service:

Transmission Service provided by in NYISO includes Network Service, Firm PTP and Non-Firm PTP. Charges for all three types of service are based on actual transmission use with billing units measured in MWh. In NYISO, EWT service includes Firm PTP Service and Non-Firm PTP Service, and is provided for time periods of varying duration. PTP Service can be used for the transmission of energy (or availability of capacity) into, out of or through the NYCA. Charges are based on actual transmission use with billing units measured in MWh.

Firm PTP Service is substantially the same as Network Service and has the same priority on the system.

Non-Firm PTP Service is similar to Network Service and Non-Firm Service, but does not include Congestion charges and has a lower priority on the system. Based on phone interviews with NYISO personnel, very few transactions take place on a Non-Firm basis.

Pricing for Network Service includes the components listed below. Pricing for Firm PTP Service includes the same components. Pricing for Non-Firm PTP Service excludes the Congestion charges.

Transmission \$ = TSC + TUC + NTAC

TSC = Transmission Service Charge, to recover the embedded costs of the Transmission Owners; assessed based on the zone in which load is located. In the case of wheel through or exports, it is based upon the zone at the point of exit.

TUC = Transmission Usage Charge, is a market-based charge that includes:

- Congestion charges
- Marginal loss charges

NTAC = NYPA Transmission Adjustment Charge, to recover the portion of NYPA’s Transmission Revenue Requirement that is not recovered through the TSC.

Transmission Service Charge

The Transmission Service Charge recovers the embedded costs of the Transmission Owners; assessed based on the zone in which load is located. In the case of wheel through or exports, it is based upon the zone at the point of exit. The TSC is calculated separately for each Transmission Owner, and includes the following:

$$\text{WHOLESALE TSC} = \{(\text{RR}/12) + (\text{CCC}/12) + (\text{LTPP}/12) - \text{SR} - \text{ECR} - \text{CRR} - \text{WR} - \text{Reserved}\}/(\text{BU}/12).^9$$

Where:

RR = The Annual Transmission Revenue Requirement, as stated in Table 1 of this Attachment. Gross Receipts Tax (“GRT”) treatment by each individual company is described in Section 5.0. Revenues from grandfathered agreements listed on Attachment H- 1 are treated as a revenue credit in the RR.

CCC = The annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner (i.e., the transmission component of control center costs) as stated on Table 1 of this Attachment.

LTPP = The Transmission Owner’s annual Net LBMP Transition Period Payment (“LTPP”) (expressed as a positive value) or receipt (expressed as a negative value) as described in Attachment K, Section 6 (Note - The LTPP will be established once for the entire LBMP Transition Period after the Initial Auction, as defined in Attachment M, for Long Term TCCs). Prior to a 205 Filing under the FPA by the Transmission Owners, the LTPP will be set at zero.

SR = SR1 + SR2. SR1 will equal the revenues from the Direct Sale by the Transmission Owner of Original Residual TCCs, TCCs derived from Existing Transmission Capacity for Native Load, and

⁹ NYISO OATT Attachment H

Grandfathered TCCs associated with ETAs, the expenses for which are included in the Transmission Owner's Revenue Requirements where the Transmission Owner is the Primary Owner of said TCCs.

SR2 will equal the Transmission Owner's revenues from the Centralized TCC Auction allocated pursuant to Attachments N. SR2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for those ETAs are included in the Transmission Owner's Revenue Requirements; and (c) TCCs derived from Existing Transmission Capacity for Native Load that are sold in the Centralized TCC Auction. Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N). SR1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (i.e., January actual data will be used in February to calculate the TSC effective in March). SR1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that the Transmission Owner will receive under each applicable TCC sold in the Direct Sale divided by the duration of the TCC (in months). SR2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR2 shall be adjusted after each Centralized TCC Auction and the revised SR2 shall be effective at the start of each Capability Period;

ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N;

CRR = The Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from ETA's, the expenses for which are included in the Transmission Owner's Revenue Requirement;

WR = The Transmission Owner's revenues from external sales (Wheels Through and Export Transactions) not associated with Existing Transmission Agreements included in Attachment L, Tables 1 and 2 and wheeling revenue, associated with OATT reservations extending beyond the start-up of the ISO. (i.e., grandfathered OATT agreements);

Reserved = Reserved1 + Reserved2 + Reserved3 + Reserved4 Reserved1 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 2.3 of Attachment N of this Tariff for the Transmission Owner's ETCNL TCCs. Reserved2 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 2.3 of Attachment N of this Tariff for the Transmission Owner's RCRR TCCs. Reserved3 will equal the value that a Transmission Owner receives for the sale of its ETCNL TCCs in a month, with the value for each ETCNL TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC. Reserved4 will equal the value that a Transmission Owner receives for the sale of its RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC;

BU = The Transmission Owner's Billing Units (annual MWh) for the Transmission District (see Table 1 of this Attachment) The Transmission Owner's BU has been adjusted upward to include subtransmission and distribution losses.

The formula above does not apply to New York Power Authority, which has its own computation. In addition, each Transmission Owner may file a separate TSC rate with FERC (or LIPA' Board of Trustees in the case of LIPA) applicable to retail access customers.

The components of the TSC are updated annually, semi-annually (related to Capability Periods) or monthly. Each Transmission Owner is required to post its TSC on the OASIS on the fifteenth of each month to be effective the first day of the following month.

Based on the foregoing, a \$/MWh TSC rate is calculated for each Transmission Owner in accordance with Section 2.1 of Attachment H of the NYISO OATT. The amount charged is equal to X) the TSC rate where the load is located, or the point of export, times Y) scheduled energy transactions. The TSC does not apply to:

1. A Transmission Owner's use of its own system to provide bundled retail service to its native load customers pursuant to a retail service tariff on file with the Public Service Commission or, in the case of the Long Island Power Authority (LIPA), has been approved by LIPA's Board of Trustees;
2. Transmission service pursuant to an existing transmission agreement whereby the otherwise applicable transmission service charge does not apply pursuant to Attachment K; or
3. Retail transmission service pursuant to any tariff or rate schedule of a Transmission Owner explicitly provides for other transmission charges in lieu of the wholesale transmission service charge, subject to any applicable provisions of the Federal Power Act.
4. Transactions curtailed by the NYISO.

The table below shows the transmission revenue requirement and aspects of various transmission charges applicable in NYISO10. As noted, the column represents the unit rate prior to crediting. The actual rates are determined pursuant to the applicable TSC formula rate, which includes reductions to the rates for revenue received by the Transmission Owners from sale of Transmission Congestion Contracts.

NYISO Wholesale TSC Calculation Information				
<u>Transmission Owner</u>	<u>Revenue Requirement</u>	<u>Scheduling, System Control and Dispatch Costs</u>	<u>Billing Units (MWh)</u>	<u>TSC Rate \$/MWh (1)</u>
Central Hudson Gas & Electric Corp.	\$16,375,919	\$1,309,980	4,723,659	\$3.74
Consolidated Edison Co. of NY, Inc.	\$385,900,000	\$21,000,000	49,984,628	\$8.14

¹⁰ NYISO OATT Attachment H

NYISO Wholesale TSC Calculation Information				
<u>Transmission Owner</u>	<u>Revenue Requirement</u>	<u>Scheduling, System Control and Dispatch Costs</u>	<u>Billing Units (MWh)</u>	<u>TSC Rate \$/MWh (1)</u>
LIPA	\$105,602,083	\$3,453,343	20,618,939	\$5.29
New York Electric & Gas Corporation (2)	\$94,143,899	\$1,633,000	14,817,111	\$6.46
Niagara Mohawk Power Corporation (Settlement OA96-194-000) (3)	\$153,619,348	\$4,539,625	34,448,060	\$4.59
Niagara Mohawk Power Corporation (Filed OA96-194-000) (4)	\$145,294,074	\$4,539,625	34,448,060	\$4.22
Orange and Rockland Utilities, Inc.	\$21,034,831	\$942,579	3,595,947	\$6.11
Rochester Gas and Electric Corp.	\$25,795,509	\$583,577	6,967,556	\$3.79

1) The rate column represents the unit rate prior to crediting; the actual rate will be determined pursuant to the applicable TSC formula rate.

2) NYSEG's RR, BU and unit Rate prior to adjustment pursuant to Attachment H, are subject to retroactive modification pursuant to the provisions of the Settlement Agreement approved by the Commission in its March 26, 2004 order issued in Docket No. EL04-56-000. For any Transmission Customer that "opts out" of the Settlement Agreement as described in paragraph 1.E thereof, the applicable NYSEG "RR" shall be \$100,541,739; the "BU" shall be 13,741,901 MWh; and, the "Rate" prior to adjustment pursuant to Attachment H, shall be \$7.4235 effective as of March 1, 2004.

3) In Niagara Mohawk Power Corp., 91 FERC ¶ 61,274 (2000), the Commission approved the revenue requirement that forms the basis of these "settlement" rates. Niagara Mohawk's "settlement" TSC applies to wholesale transmission service to all customers except Sithe/Independence Power Partners, L. P.

4) Niagara Mohawk's "filed" TSC applies only to wholesale transmission service provided to Sithe/Independence Power Partners, L.P.

The table below shows NYISO's 2006 forecast peak demand by Transmission Owner.

NYISO Forecast Load at Time of 2006 NYCA Peak	
<u>Transmission Owner</u>	<u>Forecast Load (MW)</u>
Central Hudson Gas & Electric Corp.	1,162.5
Consolidated Edison Co. of NY, Inc.	13,400.0
<u>LIPA</u>	5,234.6
Other LSEs	54.2
Municipals- Net	95.2
Other adjustments to load	22.2
New York Power Authority	584.6
<u>New York Electric & Gas Corporation</u>	2,813.8
Full Requirements Customers	36.7
Partial Requirements Customers	81.0
<u>Niagara Mohawk Power Corporation</u>	6,622.9
Full Requirements Customers	213.1
Partial Requirements Customers	126.2

NYISO Forecast Load at Time of 2006 NYCA Peak	
<u>Transmission Owner</u>	<u>Forecast Load (MW)</u>
Jamestown	89.3
Orange and Rockland Utilities, Inc.	1,130.0
Rochester Gas and Electric Corporation	1,617.0
Partial Requirements Customers	11.5
NYCA Total	<u>33,294.8</u>

The following exception applies to payment for Export or Wheel-Through Transactions¹¹:

Export or Wheel Through transactions to the New England Control Area (NECA): The EWT rate for transactions to destinations outside the New York Control Area (Export or Wheel-Through Transactions) is subject to a TSC as calculated in Attachment H. However, the TSC charge is eliminated on all Exports and Wheel-Through Transactions scheduled with the NYISO to destinations within the NECA. The tariff provides conditions for this reciprocal agreement to continue. For example, a FERC approved tariff provision remains in effect that provides for unconditional reciprocal elimination of charges on Exports and Wheel- Through Transactions from the NECA to the NYCA

Transmission Usage Charge

The TUC includes the Congestion component and the Marginal Loss component. The Congestion component is the difference between the energy components of the Location-Based Marginal Price (LBMP) at the POD and at the POR. The Marginal Loss component is the difference between the marginal loss components of the LBMP at the POD and at the POR. LBMP is the cost of the next unit of generation that would be dispatched to serve load at a particular location. Use of LBMP is intended to send price signals as to the actual cost of generation and to manage congestion. Separate Congestion charges are calculated for transactions scheduled in the Day Ahead Market and the Real-Time (Hourly) Market.

NYPA Transmission Adjustment Charge (NTAC)

The NTAC is equal to X) the difference between the NYPA Monthly Transmission Revenue Requirement and NYPA Monthly Transmission Revenue Requirement, divided by Y) NYPA Billing Units. NYPA is an agency of the State of New York and this charge ensures that NYPA collects its revenue requirement each month. The NTAC applies to all loads in the NYISO including wheel through, export and within transactions. It is a uniform, non-discountable rate. NYPA’s revenue requirements (for this calculation) are \$165,449,297 and annual billing units are 133,386,541 MWh.

¹¹ NYISO Tariff Volume I Section 7B.1 and ISO-NE OATT Section II.25.3

Seams Issues:

The NYISO has been actively working on the resolution of numerous Northeast ISO Seams issues since 2003. Many issues have been resolved. As of December 2005, among the issues that have been brought to attention of the ISOs but have either not yet resulted in a specific initiative or the initiative has not been approved as a project by the stakeholder process is the issue of Eliminating Rate Pancaking. The NYISO, with the support of the New York TOs, intends to initiate discussions among the affected parties in the Northeast to explore the potential for rate pancaking relief between New York and PJM. A meeting between the NY and PJM TOs was held on August 18, 2005 to initiate discussions on this issue. The NYISO also reports that it has initiated discussions with the Independent Electricity Operator (IESO) of Ontario to eliminate export fees¹².

Discounts:

Each Transmission Owner may advise the NYISO of discounts to its TSC applicable during a specified period to all deliveries to a particular interconnection between the NYCA and another Control Area. The NYISO shall post the discounts on the OASIS for the specified period. Three principal requirements apply to discounts for transmission services are:

- (1) Any offer of a discount made by a Transmission Owner must be announced to all eligible customers solely by posting on the OASIS;
- (2) Any customer-initiated requests for discounts (including requests for use by a Transmission Owner's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and
- (3) Once a discount is negotiated, details must be immediately posted on the OASIS.¹³

For any discount that the Transmission Owner agrees to and advises the NYISO of, the same discounted TSC rate will be offered to all transmission customers for the same period for all deliveries to a particular interconnection between the NYCA and another Control Area. The ISO will post the actual discounts on the OASIS for the specified period.

Financial Transmission Rights:

The NYISO's equivalent of FTR's are called Transmission Congestion Contracts ("TCCs"). TCCs are financial instruments that can be used to hedge costs resulting from transmission system congestion. They allow the holder to collect the congestion rent between the POR (point of withdrawal or Sink) and the POD (point of injection or Source). The holder collects (or pays, if negative) the congestion rent with transmitting one MW (in MW intervals only) from the point of injection to the point of withdrawal. The rent TCC is settled in the Day-Ahead market only. NYISO currently treats TCCs as obligations, not options.

The TCC market enables participants to buy and sell the right to collect, or the obligation to pay, day-ahead congestion charges associated with transmission between specific injection and withdrawal points. Each TCC

¹² Northeast Seams Report, Update on Northeast Seams Issues, April 20, 2006

¹³ NYISO Attachment H

represents a 1 MW transmission transaction over from specific POD to a specific POR. Both bilateral and market energy transactions are subject to congestion costs. However, these costs can be locked in with the purchase of TCCs. In NYISO, TCCs are financial instruments that enable energy buyers and sellers to hedge against fluctuations in transmission prices in the Day-Ahead Market.

TCCs may be bought or sold through direct sales or an auction. TCCs sold at an auction may be for time periods ranging from six (6) months to (5) years. The NYISO Tariff provides for an auction process to facilitate the selling of TCCs. Revenues received in the auction are given to the holder of the originally allocated TCCs and credited to the transmission service charge, which means that no TO can recover more than revenue requirements. The holder of originally allocated TCCs is defined as the Primary Holders of TCCs. The Primary Holder is whoever owned the TCCs being auctioned prior to the auction taking place. This could be the TO(s) (they were allocated TCCs for excess capacity at the start of the NYISO), owners of grandfathered contracts, developers of system expansions and market participants who have purchased TCCs in prior auctions that they no longer want to hold. Revenues received from the TCC auction are used to offset revenue requirements.

The NYISO has two auction processes to acquire TCCs¹⁴. They are:

Capability Period Auctions

The Capability Period Auction consists of a series of sub-Auctions. The NYISO conducts these sub-Auctions in two Stages, with each Stage including several rounds. The transmission capacity that has been offered for sale in Stage 1 is auctioned in not less than four rounds, unless the TOs unanimously consent to fewer rounds. A portion of the capacity available for sale as TCCs will be Auctioned in each of those rounds.

Reconfiguration Auctions

Following the Capability Period Auction, the NYISO will conduct Reconfiguration Auctions on a monthly basis. Primary Holders of TCCs that are valid for the next month may offer those TCCs for sale in the Reconfiguration Auction for that month. TCCs awarded in a Reconfiguration Auction will be valid for one month.

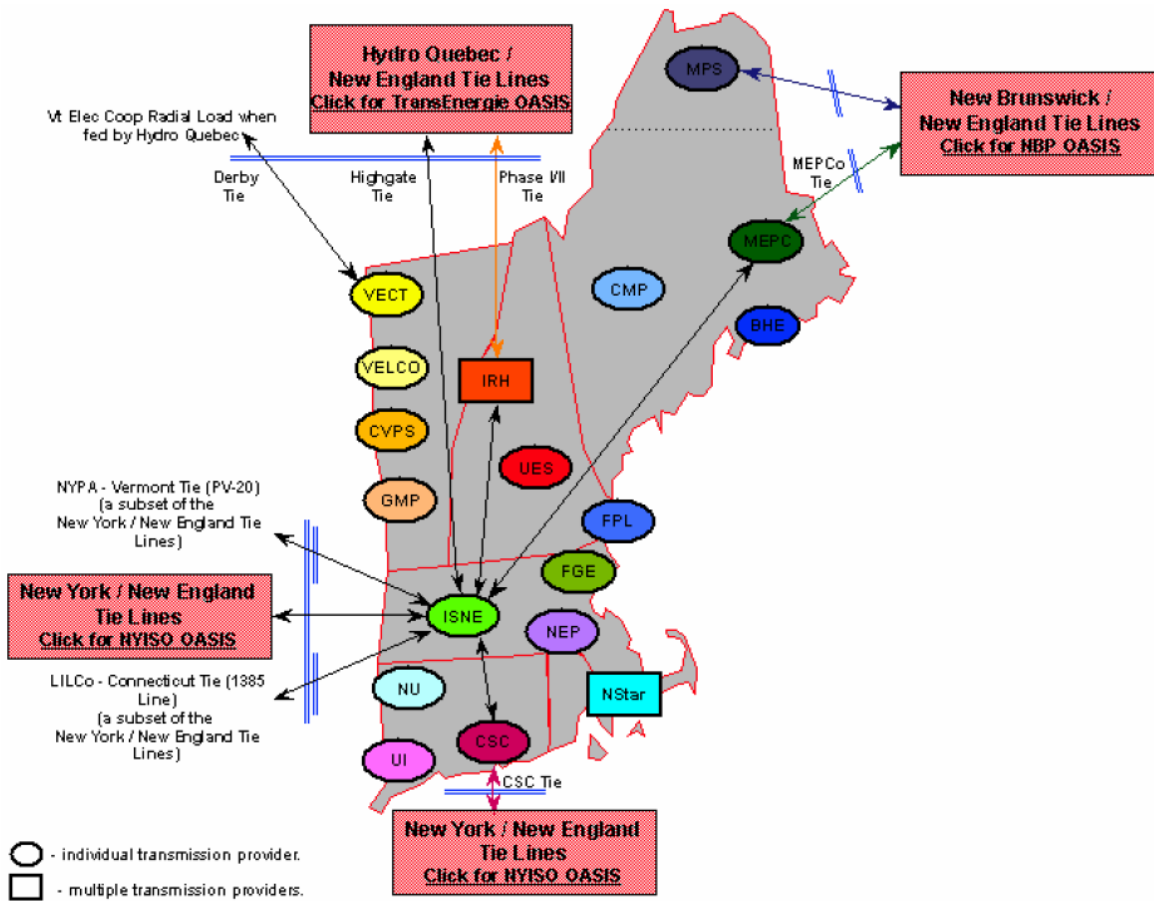
¹⁴ NYISO Transmission Congestion Contract Manual

SECTION V

INDEPENDENT SYSTEM OPERATOR OF NEW ENGLAND (ISO-NE)

On February 1, 2005, ISO New England (ISO-NE) became a FERC approved RTO. While it continues to perform coordination, scheduling, billing, etc duties it now exercises day-to-day operational control of the transmission system under agreements with existing transmission companies. Equally important, it is the single point-of-control to effectively maintain reliability and preserve the integrity of the region’s bulk power system on a daily basis and in emergency situations.

The following map illustrates the ISO-NE control area and its interconnections.



The eight transmission owners are:

- Bangor Hydro
- Boston Edison
- Central Maine Power
- Commonwealth Energy
- National Grid
- Northeast Utilities
- United Illuminating
- Vermont Electric Light

Transmission open access provides the ability to make use of existing transmission facilities that are owned by others, in this case the Pool Transmission Owners (PTO) in New England that make their Pool Transmission Facilities (PTF) available under the Transmission Operating Agreement (Agreement) and the OATT, to deliver to customers power and the ancillary services that are necessary to make the transport of power possible..

The PTF are operated as part of a single New England Control Area (NECA), with free-flowing transmission ties to New York and New Brunswick and Direct Current (DC) ties to Quebec. ISO-NE manages the operation of these PTF in accordance with the Agreement. The tie to New Brunswick and the Direct Current (DC) ties to Quebec and Long Island are not PTF.

The OATT also provides for Merchant Transmission Facilities (MTF) that are not PTF; currently the only MTF under the OATT is the Cross Sound Cable, a DC tie between Connecticut and Long Island (in the NYISO).

Transmission Pricing and Rate Design

On March 1, 2003, ISO-NE transitioned from an interim market design by implementing its Standard Market Design (SMD), a major redesign of the region's wholesale electricity market. This market structure provides for a more economically efficient marketplace and reliable power system for the six-state region. The three most prominent features of ISO NE's SMD are the introduction of locational prices for energy, a multi-settlement system and expanded risk management opportunities.

To simplify trading under SMD, the New England transmission system is also divided into eight pricing zones and a hub. The eight zones are: Maine, Vermont, New Hampshire, WC Mass, NE Mass & Boston, SE Mass, Rhode Island and Connecticut. The Locational Marginal Price (LMP) for each zone is the load weighted average of each of the nodal LMPs that make up the zone. The LMP for the hub is the simple average LMP from each of the LMP nodes that make up the hub.

The multi-settlement process for the energy market consists of day-ahead and real-time markets for electricity, each producing its own separate and unique financial settlement. The first settlement relates to the day-ahead market's costs and payments while the second settles the difference between energy scheduled day-ahead and that which is actually delivered in real-time.

ISO-NE also implemented the opportunity to hedge, or protect, against the adverse impacts of having to pay higher LMPs, Market participants are able to bid for the rights to a share of the congestion revenue through monthly and long-term Financial Transmission Right (FTR) auctions.

Possible charges for Transmission Customers under the OATT are:

Regional Network Service (RNS) Customers is transmission service for the delivery of energy and capacity in Network Resources and delivery to or by Network Customers of energy and capacity in Market transactions. RNS must be taken and paid for by each Eligible Customer which has a load within the NECA unless the Eligible Customer operates its own Control Area. RNS customers must also take Local Network Service except as otherwise provided in the OATT. Further information concerning Network Service can be found at www.iso-ne.com, (ISO-NE OATT, Rate Schedules, user manuals, etc).

Point-to-Point Transmission Service (PTP Service) Customers receive Through or Out Service. Through or Out Service means a transaction that flows over the PTF but does not originate or terminate in the NECA, or a transaction which originates at a point on the PTF and flows over the PTF before passing out of the NECA.

Point-to-Point Service or Through or Out Service:

In ISO-NE, Through or Out Services are billed to the entity requesting the reservation on OASIS, and are billed on a transaction basis.

The rate per hour for Through or Out Service is the annual Pool PTF Rate divided by 8,760 (hours). The Pool PTF Rate, determined annually in accordance with paragraph (2) of Schedule 8 of the OATT, is equal to X) the sum for all participants of annual transmission revenue requirements determined in accordance with Attachment F divided by Y) the sum of the coincident Monthly Peaks of all local networks.

The PTF Rate is applied to the Reserved Capacity for the transaction, which is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the POR and the POD under the OATT. Reserved Capacity is expressed in whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Revenues are distributed to the TOs in proportion to their share of PTF revenue requirements.

Current rates¹⁵ for Through or Out service are as shown in the table below.

ISO NEW ENGLAND PTP RATES			
TERM OF SERVICE	UNIT OF COST	FIRM RATE	NON-FIRM RATE
Yearly	\$/kW- yr	\$20.32	Not available
Monthly	\$/kW- mo	\$1.69	
Weekly	\$/kW- wk	\$0.39	
Daily	\$/MW- day	\$55.68	
Hourly	\$/MWh	\$2.32	\$2.32

The monthly revenues from Through or Out transactions are distributed to the appropriate Transmission Owner based on POD or allocated based on flow distribution factors between the transaction’s POR and POD. This allocation appears as a credit on the OATT portion of the bill¹⁶.

¹⁵ ISO-NE file: sch_9_effective_3-1-06_v1.xls

The following exception applies to payment for Through or Out Service¹⁷:

Through or Out Service Charges to New York Control Area (NYCA): The Through or Out rate for any Through or Out Service transaction that (a) goes through or out of the NECA and (b) has the New England/NYCA boundary as its POD is zero. The reduction to zero of the Through or Out rate to New York only applies to Schedule 8 (PTP Service) charges. The reduction to zero does not apply to Regional Network Load located outside of the NECA; those customers continue to pay the full T or O Rate as applied to the amount reserved for the Regional Network Load which is not physically interconnected with the PTF. The tariff provides conditions for this reciprocal agreement to continue. For example, that a FERC approved tariff provision remains in effect that provides for unconditional reciprocal elimination of charges on Through or Out Service from the NYCA to the NECA.

Rate Surcharge Adders:

No adders apply.

Discounts:

Three principal requirements apply to discounts for Through or Out Service as follows¹⁸:

1. any offer of a discount made by the PTOs must be announced to all Eligible Customers solely by posting on the OASIS,
2. any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and
3. once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the PTO must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the PTF.

Financial Transmission Rights:

ISO-NE introduced FTRs to provide a mechanism for customers to manage the risks of costs associated with congestion.

A Financial Transmission Right¹⁹ (FTR) is a financial instrument that entitles the holder to receive compensation for Congestion Costs that arise when the transmission grid is congested in the Day-Ahead Energy Market and differences in Day-Ahead Locational Marginal Prices (LMPs) result from the dispatch of generators to relieve the congestion. Each FTR is unidirectional and is defined in megawatts from a point of receipt (where the power is injected onto the New England grid) to a point of delivery (where the power is withdrawn from the New England grid). For each hour in which congestion exists on the New England Transmission System between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the congestion charges collected for that hour. Non-PTF external interfaces are excluded from the FTR Auction because flows over those

¹⁶ ISO New England Manual for Tariff Accounting Manual M-27

¹⁷ ISO-NE OATT Section II.25.3 and NYISO Tariff Volume I Section 7B.1

¹⁸ ISO-NE OATT, Schedule 8

¹⁹ ISO-NE Manual for Financial Transmission Rights

facilities are limited to those with transmission reservations and, therefore, there will be no congestion over those facilities because external interface limits are honored in the clearing of the Day-Ahead Energy Market. Since there is no congestion over these facilities in the Day-Ahead Energy Market, there is no need to offer FTRs.

FTRs entitle the holder to payments based on the congestion costs associated with a particular energy transaction and, thus, can be used as a hedge against those costs. Essentially, FTRs are financial entitlements to congestion charges paid by transmission customers and congestion paying entities. They do not represent a right for physical delivery of power.

The holders of FTRs receive compensation for congestion costs that arise when the transmission grid is congested in the day-ahead energy market and differences in day-ahead LMPs resulting from the dispatch of generators to relieve the congestion. Each FTR is unidirectional and is defined in megawatts from a POR (where the power is injected onto the ISO-NE grid) to a POD (where the power is withdrawn from the ISO-NE grid). For each hour in which congestion exists on the NEPOOL transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the congestion charges collected for that hour.

FTRs can be acquired in two ways:

1. FTR Auction – The ISO conducts periodic auctions to allow eligible FTR bidders to acquire FTRs, and allows FTR holders an opportunity to sell FTRs. ISO-NE offers annual and monthly FTR auctions, to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs. The auctions are conducted by the ISO in accordance with the provisions of Market Rule 1 Section III.7. Non-Market Participants that want to participate in the FTR Auction or to become an FTR Holder via the secondary market may do so after having satisfied the applicable financial assurance criteria
2. Secondary Market – The FTR secondary market is a market in which FTR holders and other entities that have acquired FTRs sell FTRs on a bilateral basis.

When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of Financial Transmission Rights in the Form of Options; that is, FTRs that do not create potential obligations to pay.

SECTION VI

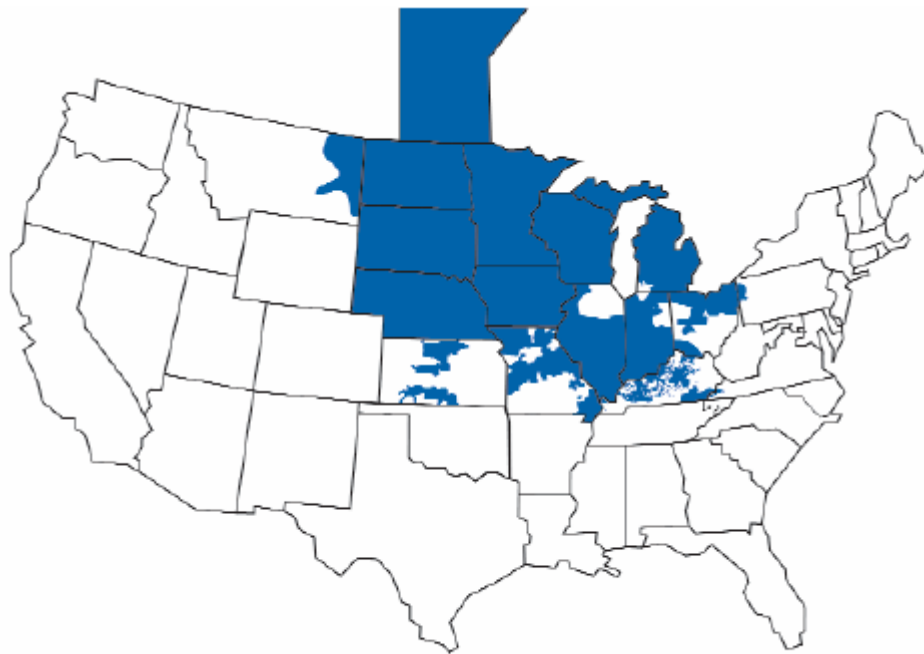
MIDWEST INDEPENDENT SYSTEM OPERATOR (MISO)

Background

The Midwest Independent Transmission System Operator, Inc. (MISO) is a non-profit, member-based organization. The Midwest ISO manages one of the world’s largest energy markets using security-constrained economic dispatch of generation. Market operations include a Day-Ahead Market, a Real-Time Market, and a Financial Transmission Rights (FTR) Market. These markets are operated and settled separately.

The MISO administered grid interconnects with the Independent Electricity System Operator of Ontario, the Mid-Continent Area Power Pool, PJM, Southwest Power Pool and the Tennessee Valley Authority. The MISO has seams agreements or memorandums of understanding with each of these organizations to facilitate operations.

The following map illustrates MISO’s reliability area.



Midwest ISO Reliability Area

Network Service

MISO offers Network Transmission Service for network customers. Further information on Network Transmission Service is available at www2.midwestiso.org, (MISO OATT, Rate Schedules, user guides, etc).

Point-to-Point Transmission Service

PTP Service is for the receipt of capacity and energy at designated POR(s) and the transmission of such capacity and energy to designated POD(s). Firm PTP Service charges are set forth in Schedule 7 of the OATT, and Non-Firm PTP Service charges in Schedule 8, except that for POR and POD located within the Transmission System (Michigan), Firm PTP Service is pursuant to under Schedule 7 - Michigan and Non-Firm PTP Service is pursuant to Schedule 8 - Michigan.

Zonal Rates: The Transmission Customer pays the zonal rate (per KW of reserved capacity) based upon the zone where the load is located for (1) Firm PTP Service where the generation source is outside MISO and the load is located in MISO and (2) Firm PTP Service where both the generation source and the load are located within MISO. All Transmission Customers with load in GridAmerica Zone 8B pay rate for 138 kV and Above Service rate; Customers with load in GridAmerica Zone 8B served by transmission facilities below 138 kV also pay the below 138 kV transmission service rate for its load.

Single System-Wide Rates: The Transmission Customer pays the applicable single system-wide rate for (1) Firm PTP Service where the generation source is within MISO and the load is outside MISO; and (2) Firm PTP Service where both the generation source and the load are located outside MISO

The minimum term of Firm PTP Service is one day and the maximum term is specified in each Service Agreement. Firm Point-to-Point rates are shown in the table below²⁰

MISO Rates for Firm PTP Service Pursuant to EMT Schedule 7, Effective April 1, 2006						
Zone	Name	\$MW/ Year	\$MW/ Month	On-Peak \$MW/ Week	On-Peak \$MW/ Day	Off- Peak \$MW/ Day
	Midwest ISO Drive-Through and Out rate /2	\$19,389.19	\$1,615.77	\$372.87	\$74.57	\$53.27
1	Alliant Energy West	\$26,390.46	\$2,199.20	\$507.51	\$101.50	\$72.50
2A	ATCLLC Madison G&E	\$30,523.23	\$2,543.60	\$586.99	\$117.40	\$83.86
2B	ATCLLC Wisconsin Public Service	\$30,523.23	\$2,543.60	\$586.99	\$117.40	\$83.86
2C	ATCLLC Wisconsin P&L	\$30,523.23	\$2,543.60	\$586.99	\$117.40	\$83.86
2D	ATCLLC Wisconsin Energy	\$30,523.23	\$2,543.60	\$586.99	\$117.40	\$83.86
2E	ATCLLC UPPC	\$30,523.23	\$2,543.60	\$586.99	\$117.40	\$83.86
3	Central Illinois Light Co.	\$8,641.91	\$720.16	\$166.19	\$33.24	\$23.74
4	Cinergy Services (including IMPA & VPA)	\$15,028.67	\$1,252.39	\$289.01	\$57.80	\$41.29
5	City of Columbia, Missouri	\$11,530.37	\$960.86	\$221.74	\$44.35	\$31.68
6	City Water, Light & Power (Springfield, IL)	\$23,830.80	\$1,985.90	\$458.28	\$91.66	\$65.47
7	Great River Energy	\$27,121.79	\$2,260.15	\$521.57	\$104.31	\$74.51
8A	GridAmerica Ameren	\$9,990.55	\$832.55	\$192.13	\$38.43	\$27.45

²⁰ MISO OATT Schedule 7 effective April 1, 2006 (Posting 2006 Mar 23.pdf)

MISO Rates for Firm PTP Service Pursuant to EMT Schedule 7, Effective April 1, 2006						
Zone	Name	\$MW/ Year	\$MW/ Month	On-Peak \$MW/ Week	On-Peak \$MW/ Day	Off- Peak \$MW/ Day
8A.1	MJMEUC /2	\$9,213.91	\$767.83	\$177.19	\$35.44	\$25.31
8B.1	GridAmerica American (138 KV and Above)	\$10,673.05	\$889.42	\$205.25	\$41.05	\$29.32
8B.2	GridAmerica American (Below 138 KV)	\$11,086.61	\$923.88	\$213.20	\$42.64	\$30.46
8C	GridAmerica Northern IN Public Service	\$26,400.04	\$2,200.00	\$507.69	\$101.54	\$72.53
9	Hoosier Energy	\$39,219.74	\$3,268.31	\$754.23	\$150.85	\$107.7 5
10	Illinois Power	\$11,067.06	\$922.26	\$212.83	\$42.57	\$30.40
11	International Transmission Company	\$19,310.33	\$1,609.19	\$371.35	\$74.27	\$53.05
12	Indianapolis Power & Light	\$9,486.70	\$790.56	\$182.44	\$36.49	\$26.06
13	Louisville G & E/Kentucky Utilities	\$9,320.86	\$776.74	\$179.25	\$35.85	\$25.61
14	Lincoln Electric (Neb.) System	(zonal pricing not yet effective)				
15	Michigan Joint Zone	\$20,758.66	\$1,729.89	\$399.20	\$79.84	\$57.03
16	Minnesota Power	\$19,329.18	\$1,610.76	\$371.71	\$74.34	\$53.10
17	Montana-Dakota Utilities Co.	\$36,650.67	\$3,054.22	\$704.82	\$140.96	\$100.6 9
18	NSP Companies	\$22,997.11	\$1,916.43	\$442.25	\$88.45	\$63.18
19	Otter Tail Power	\$40,654.08	\$3,387.84	\$781.81	\$156.36	\$111.6 9
20	Southern Illinois Power Cooperative	\$26,357.50	\$2,196.46	\$506.88	\$101.38	\$72.41
21	Southern Minnesota Municipal Power Agency	\$32,007.61	\$2,667.30	\$615.53	\$123.11	\$87.93
22	Aquila, Inc. Kansas	(zonal pricing not yet effective)				
23	Aquila, Inc. Missouri	(zonal pricing not yet effective)				
24	Vectren Energy	\$10,758.17	\$896.51	\$206.89	\$41.38	\$29.56
	Manitoba Hydro \$US /1	\$35,936.00	\$2,994.67	\$691.08	\$138.22	\$98.73
1/ Rate capped at weekly rate 2/ MISO rate includes all zones plus Manitoba Hydro 3/ Calculated using fixed exchange rate. See Manitoba Hydro OASIS for C\$ rates http://www.hydro.mb.ca 4/ Select MJMEUC members per 6-24-05 order for Docket No. ER04-1252.						

Non-Firm PTP Service is available for periods from one hour to one month. However, a Purchaser of Non-Firm PTP Service is be entitled to reserve a sequential term of service (such as a sequential monthly term without

having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month. Non-Firm PTP rates are shown in the table below²¹

MISO Rates for Non-Firm PTP Service Pursuant to EMT Schedule 8, Effective April 1, 2006							
Zone	Name	\$MW/ Year	\$MW/ Month	On- Peak \$MW/ Week	On- Peak \$MW/ Day	Off- Peak \$MW/ Day	Off- Peak \$MW/ Day
	Midwest ISO Drive-Through and Out rate /2	\$2,199.20	\$507.51	\$101.50	\$6.3439	\$72.5013	\$3.0209
1	Alliant Energy West	\$2,543.60	\$586.99	\$117.40	\$7.3373	\$83.8550	\$3.4940
2A	ATCLLC Madison G&E	\$2,543.60	\$586.99	\$117.40	\$7.3373	\$83.8550	\$3.4940
2B	ATCLLC Wisconsin Public Service	\$2,543.60	\$586.99	\$117.40	\$7.3373	\$83.8550	\$3.4940
2C	ATCLLC Wisconsin P&L	\$2,543.60	\$586.99	\$117.40	\$7.3373	\$83.8550	\$3.4940
2D	ATCLLC Wisconsin Energy	\$2,543.60	\$586.99	\$117.40	\$7.3373	\$83.8550	\$3.4940
2E	ATCLLC UPPC	\$720.16	\$166.19	\$33.24	\$2.0774	\$23.7415	\$0.9892
3	Central Illinois Light Co.	\$1,252.39	\$289.01	\$57.80	\$3.6127	\$41.2876	\$1.7203
4	Cinergy Services (including IMPA & VPA)	\$960.86	\$221.74	\$44.35	\$2.7717	\$31.6769	\$1.3199
5	City of Columbia, Missouri	\$1,985.90	\$458.28	\$91.66	\$5.7286	\$65.4692	\$2.7279
6	City Water, Light & Power (Springfield, IL)	\$2,260.15	\$521.57	\$104.31	\$6.5197	\$74.5104	\$3.1046
7	Great River Energy	\$832.55	\$192.13	\$38.43	\$2.4016	\$27.4466	\$1.1436
8A	GridAmerica Ameren	\$767.83	\$177.19	\$35.44	\$2.2149	\$25.3129	\$1.0547
8A.1	MJMEUC /2	\$889.42	\$205.25	\$41.05	\$2.5656	\$29.3216	\$1.2217
8B.1	GridAmerica American (138 KV and Above)	\$923.88	\$213.20	\$42.64	\$2.6650	\$30.4577	\$1.2691
8B.2	GridAmerica American (Below 138 KV)	\$2,200.00	\$507.69	\$101.54	\$6.3462	\$72.5276	\$3.0220
8C	GridAmerica Northern IN Public Service	\$3,268.31	\$754.23	\$150.85	\$9.4278	\$107.7465	\$4.4894
9	Hoosier Energy	\$922.26	\$212.83	\$42.57	\$2.6604	\$30.4040	\$1.2668
10	Illinois Power	\$1,609.19	\$371.35	\$74.27	\$4.6419	\$53.0504	\$2.2104
11	International Transmission Company	\$790.56	\$182.44	\$36.49	\$2.2805	\$26.0624	\$1.0859
12	Indianapolis Power & Light	\$776.74	\$179.25	\$35.85	\$2.2406	\$25.6068	\$1.0669
13	Louisville G & E/Kentucky Utilities	(zonal pricing not yet effective)					

²¹ MISO OATT Schedule 8 effective April 1, 2006 (Posting 2006 Mar 23.pdf)

MISO Rates for Non-Firm PTP Service Pursuant to EMT Schedule 8, Effective April 1, 2006							
Zone	Name	\$MW/ Year	\$MW/ Month	On- Peak \$MW/ Week	On- Peak \$MW/ Day	Off- Peak \$MW/ Day	Off- Peak \$MW/ Day
14	Lincoln Electric (Neb.) System	\$1,729.89	\$399.20	\$79.84	\$4.9901	\$57.0293	\$2.3762
15	Michigan Joint Zone	\$1,610.76	\$371.71	\$74.34	\$4.6464	\$53.1021	\$2.2126
16	Minnesota Power	\$3,054.22	\$704.82	\$140.96	\$8.8103	\$100.6887	\$4.1954
17	Montana-Dakota Utilities Co.	\$1,916.43	\$442.25	\$88.45	\$5.5282	\$63.1789	\$2.6325
18	NSP Companies	\$3,387.84	\$781.81	\$156.36	\$9.7726	\$111.6870	\$4.6536
19	Otter Tail Power	\$2,196.46	\$506.88	\$101.38	\$6.3359	\$72.4107	\$3.0171
20	Southern Illinois Power Cooperative	\$2,667.30	\$615.53	\$123.11	\$7.6941	\$87.9330	\$3.6639
21	Southern Minnesota Municipal Power Agency	(zonal pricing not yet effective)					
22	Aquila, Inc. Kansas	(zonal pricing not yet effective)					
23	Aquila, Inc. Missouri	\$896.51	\$206.89	\$41.38	\$2.5861	\$29.5554	\$1.2315
24	Vectren Energy	\$2,994.67	\$691.08	\$138.22	\$8.6385	\$98.7253	\$4.1136
	Manitoba Hydro \$US /1	\$2,199.20	\$507.51	\$101.50	\$6.3439	\$72.5013	\$3.0209
1/ Rate capped at weekly rate 2/ MISO rate includes all zones plus Manitoba Hydro 3/ Calculated using fixed exchange rate. See Manitoba Hydro OASIS for C\$ rates (http://www.hydro.mb.ca) 4/ Select MJMEUC members per 6-24-05 order for Docket No. ER04-1252.							

Regional Through and Out Service (RTOR) Adder

Each Transmission Customer taking Transmission Service going out²² or through²³ the MISO system shall compensate MISO for a Regional Through and Out Rate (“RTOR”) charge²⁴, which is in addition to the charges in Schedules 7 and 8 and any other applicable charges in the Tariff. The RTOR charge was originally implemented to compensate transmission owners for lost revenue due to the elimination of rate pancaking. The

²² Out Transmission Service means service where the source is in Control Areas inside the ISO Transmission System and the sink is in Control Areas outside the ISO Transmission System.

²³ Through Transmission Service means service where the source and the sink are in Control Areas outside of the ISO Transmission System.

²⁴ OATT Schedule 14, Regional Through and Out Rate , effective April 1, 2006

RTOR shall remain effective for a six-year Transition Period²⁵ and will expire January 31, 2008. However, pursuant to FERC Order, RTOR on exports to PJM were eliminated December 1, 2004.

The RTOR charge is applied to reserved capacity as follows:

Annual	\$9.36 kW/Year
Monthly	\$0.78 kW/Month
Weekly	\$0.18 kW/Week
On-Peak Daily	\$0.036 kW/Day
On-Peak Hourly	\$2.25 MWh
Off-Peak Daily	\$0.026 kW/Day
Off-Peak Hourly	\$1.071 MWh

Rates to the PJM Interconnection, LLC:

In accordance with FERC’s November 18, 2004 Order in Docket Nos. ER05-6, EL04-135, EL02-111 and EL03-212, Midwest Independent Transmission System Operator, Inc. 109 FERC ¶ 61,168 (2004), beginning April 1, 2006, the charge under Schedule 7, Section (2) (Single System-Wide Rates) for Points of Delivery at the border of the Transmission Provider Region shall not apply to all transactions to serve loads within the area served under the open access transmission tariff on file with the Commission of PJM Interconnection, LLC, where transmission service is taken under the PJM Interconnection, LLC open access transmission tariff.

Seams:

Seams Elimination Charge/Cost Adjustments/Assignments (SECA) is the mechanism for recovery of the lost revenues resulting from the elimination of the through and out rates for transactions between MISO and PJM. Schedule 21 of the OATT sets out the monthly SECA amounts to be paid by entities that are part of the PJM interconnection, L.L.C. (“PJM”) for (1) the period beginning on December 1, 2004 and ending on March 31, 2005, and (2) the subsequent period beginning on April 1, 2005 and ending on March 31, 2006. The charge is no longer in effect.

Financial Transmission Rights (FTR):

MISO functions as the facilitator of the FTR process. FTRs are issued by the Transmission Provider through allocation, assignment, auction or any other process accepted by the FERC. In order to acquire FTRs, Market Participants (“MPs”) must participate annually in the Annual FTR Registration process. Every Annual FTR Registration and Allocation covers a period of one year (four seasons) from June 1 to May 31 of the following year. FTRs do not represent a physical right for delivery of energy.

The key characteristics of the MISO FTRs are²⁶:

- Only MPs can hold FTRs, however MPs can be agents for other entities.
- FTRs do not represent a physical right for delivery of energy.
- Market Participants (MPs) need not hold FTRs to schedule Physical or Financial Bilateral Transactions.

²⁵ The Transition Period begins when the Transmission Owners transfer operational control of the Transmission System to the ISO.

²⁶ MISO Business Practices Manual for Financial Transmission Rights

- FTR Holders are not required to schedule Physical or Financial Bilateral Transactions by virtue of holding FTRs.
- FTRs do not provide any physical scheduling priority in the Day-Ahead Energy Market.
- FTRs do not protect MPs from Transmission Congestion Charges related to scheduling power in the Real-Time Energy Market or deviating from the amounts that they scheduled in the Day-Ahead Energy Market.

MISO issues and makes the following types of FTRs available to Market Participants:

- Receipt Point-to-Delivery Point FTR Obligation
- Receipt Point-to-Delivery Point FTR Option (when supportable)

SECTION VII

TRANSENERGIE

TransÉnergie is in charge of the Québec Control Area, which includes Labrador and the Alcan and Maclaren power systems. TransÉnergie is the transmission provider for Hydro-Québec’s system. It is a division of Hydro-Québec, created in 1997. In Québec, TransÉnergie’s operations are regulated by the Régie de l’énergie (Régie or Energy Board) on the basis of cost of service, and both its rates and capital projects must be approved by the Régie de l’énergie.

TransÉnergie is interconnected with Ontario, Newfoundland and Labrador, New Brunswick provinces, as well as New York ISO, and ISO-New England. TransÉnergie has 18 interconnections, providing a total export capacity of more than 7,100 MW and an import capacity of more than 9,300 MW. These facilities allow interchanges with Newfoundland and Labrador, New Brunswick, Ontario, New York and New England.

The following map illustrates TransÉnergie’s control area.



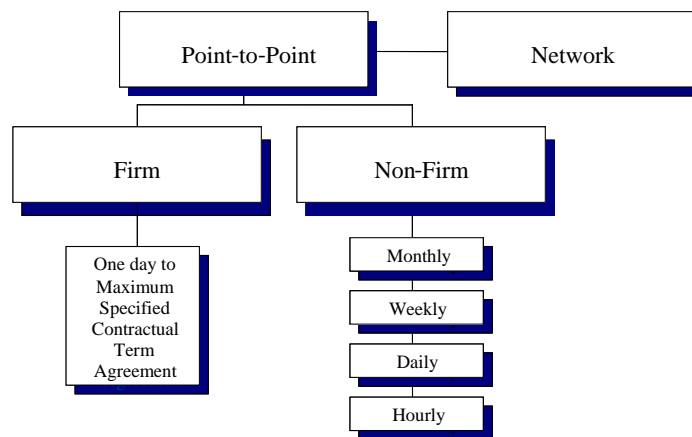
Transmission Pricing and Rate Design

TransEnergie offers Network Service as well as Firm and Non-Firm PTP services.

The diagram on the following page illustrates the main elements of TransEnergie transmission tariff.

PTP transmission service is for the receipt of capacity and energy at designated PORs and the transmission of such capacity and energy to designated PODs. The minimum term of firm PTP transmission service shall be one day and the maximum term shall be specified in the service agreement. Long-term PTP transmission service is available on a first-come, first-served basis.

Non-firm PTP transmission service is available for periods ranging from one hour to one month. However, a purchaser of Non-Firm PTP transmission service may reserve a sequential term of service, so that the total time period for which the reservation applies is greater than one month.



Point-to-Point Services:

Long-Term Firm and Short-Term Firm PTP Transmission Service

The transmission customer compensates the transmission provider each month for reserved capacity at the sum of the applicable charges below²⁷:

- 1) *Yearly delivery*: one-twelfth of the demand charge of \$61.97/kW of reserved capacity per year.

²⁷ Schedules 7 and 8 of the *Hydro-Québec Open Access Transmission Tariff*.
<http://www.hydroquebec.com/transenergie/oasis/en/tarif.shtml>

- 2) *Monthly delivery*: \$5.17/kW of reserved capacity per month.
- 3) *Weekly delivery*: \$1.19/kW of reserved capacity per week.
- 4) *Daily delivery*: \$0.24/kW of reserved capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the Weekly rate, times the highest kW of reserved capacity in any day during such week.

Non-Firm PTP Transmission Service

The transmission customer shall compensate the transmission provider for Non-Firm PTP transmission service up to the sum of the applicable charges set forth below²⁸:

- 1) *Month delivery*: \$5.17/kW of reserved capacity per month.
- 2) *Weekly delivery*: \$1.19kW of reserved capacity per week.
- 3) *Daily delivery*: \$0.24/kW of reserved capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in Section (2) above, times the highest amount in kilowatts of reserved capacity in any day during such week.
- 4) *Hourly delivery*: The charge is that agreed upon by the parties at the time service is reserved but can not exceed \$7.08/MWh. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the Daily rate, times the highest kW of reserved capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly or daily delivery, shall not exceed the Weekly rate, times the highest kW of reserved capacity in any hour during such week.

Rate Surcharge Adders:

No adders apply.

Seams issues:

TransEnergie has informed Rudden that it is engaged in discussions with ISO-NE and NYISO concerning Seams issues as part of the group of ISO's addressing NE Seams issues.

Discounts:

No discounts are offered.

Financial Transmission Rights:

²⁸ Schedules 7 and 8 of the *Hydro-Québec Open Access Transmission Tariff*.
<http://www.hydroquebec.com/transenergie/oasis/en/tarif.shtml>

TransEnergie has advised Rudden that it does not offer Financial Transmission Rights or other mechanisms to allow for hedging of congestion costs.

SECTION VIII

EVOLVING RULES AND RECENT RTO DEVELOPMENTS

Energy Policy Act of 2005

On August 8, 2005, following four years of debate in Congress, President George W. Bush signed the Energy Policy Act of 2005 (“EPAAct 2005”) into law. The Electricity Section of the Act is contained in Title XII, Section 1201, also known as “Electricity Modernization Act of 2005”. Among the features of the Act that have the potential to impact PTP Transmission Service is the following:

The Act requires DOE to issue a national transmission congestion study for comment by August 2006 and every three years thereafter. Based on the study and public comments, DOE may designate selected geographic areas as "National Interest Electric Transmission Corridors." Applicants for projects proposed within designated corridors that are not acted upon by state siting authorities within one year may request FERC to exercise federal "backstop" siting authority.

Department of Energy's Notice of Inquiry of February 2, 2006, a request for designation of two "National Interest Electric Transmission Corridors." The Notice of Inquiry sought comments on issues relating to the Congestion Study and Designation of National Interest Electric Transmission Corridors. Both reliability and congestion should be improved as a result of this effort.

PJM response - On March 6, 2006, PJM filed, pursuant to Section 1221(a) of the EPAAct 2005 and the U.S. Department of Energy's Notice of Inquiry of February 2, 2006, 71 Fed. Reg. 5660, a request for designation of two "National Interest Electric Transmission Corridors." The proposed corridors are referred to as the Allegheny Mountain path and the Delaware River path. PJM requested that the Department designate these paths as national interest corridors by August 2006.

NYISO and PJM response - In response to the Department of Energy's Notice of Inquiry (NOI) regarding its upcoming Congestion Study and its role in designating National Interest Electric Transmission Corridors (“NIETC”), as a member of the ISO/RTO Council (“IRC”)²⁹, submitted supplemental comments. The comments focused on two issues. Essentially:

1. The IRC is concerned that the Department's two step process, although well intentioned, unnecessarily complicates an already lengthy and litigious process for siting major new transmission lines. The concern is that the DOE runs the risk of duplicating, if not usurping, the role of state siting processes, and ultimately limiting the FERC's options in its exercise of backstop siting authority.

²⁹ The members of the IRC are the Alberta Electric System Operator (“AESO”); California Independent System Operator Corporation (“CAISO”); Electric Reliability Council of Texas (“ERCOT”); the Independent Electricity System Operator of Ontario (“IESO”); ISO New England Inc. (“ISO-NE”); Midwest Independent Transmission System Operator, Inc. (“MISO”); New York Independent System Operator, Inc. (“NYISO”); PJM Interconnection, L.L.C. (“PJM”); and the Southwest Power Pool (“SPP”).

Also, the proposed two-step process adds significant legal and policy complications with the Corridor process.

2. Should the DOE proceed with approving specific projects, its proposed criteria are far too vague to determine whether one transmission project versus another transmission project is appropriate. Instead, the DOE would need to develop criteria that analyze, among other things: violations of NERC criteria, reviews of loop flows and other causes of congestion, the impact of planned generation on resolving the constraint, and the potential impact of “at risk” generation. The DOE would need to develop sensitivity analyses around load forecasts. All of these steps are undertaken in the RTO/ISO planning processes making such a review unnecessary unless the DOE were to certify transmission alternatives under its proposed two-step process. However, the need to revise the criteria in order to undertake a meaningful review and certification of projects highlights the very problem with reviewing alternatives: such detailed criteria would quickly run afoul of the much higher level criteria that Congress set forth to govern the DOE’s reviews.

FERC Notice of Proposed Rulemaking³⁰ (NOPR), May 19, 2006 - “Preventing Undue Discrimination and Preference in Transmission Service” (Docket Nos. RM05-25-000 and RM05-17-000)

The FERC proposed amendments to its regulations adopted in April of 1996 - Order Nos. 888 (Transmission Open Access) and 889 (OASIS) to ensure transmission services are provided in a nondiscriminatory and just and reasonable basis. The proposal marks the first major reform of the open-access transmission tariff (OATT) enacted 10 years ago.

Comments are due on this NOPR 60 days after it was published.

FERC looks to strengthen the OATT and address deficiencies that it states have become apparent over the decade since its adoption, particularly in the areas of Available Transfer Capability (ATC) calculation and transmission planning. According to the FERC the reforms are not, however, designed to create new market structures, divest control over transmission, impinge on state jurisdiction, or weaken the protection of native load customers.

The Commission concluded as long ago as December 1999, in Order No. 2000, that transmission providers retained the incentive and ability to discriminate against third-party users of their transmission systems, particularly in areas where the pro forma OATT left the transmission provider with significant discretion. In Order No. 2003, the Commission similarly found that interconnection requirements could be used to discriminate. The proposed rulemaking is another action by the Commission designed to enhance the regulatory framework established in Order No. 888 and Order No. 889³¹.

Through the new OATT embodied in the NOPR, the Commission seeks to increase transparency and clarity in the planning and use of the transmission system while addressing ambiguities in the original pro forma OATT.

Among the OATT reforms the Commission is proposing are the following:

³⁰ FERC NOPR

³¹ FERC May 18, 2006 Press Release

- **Consistency and Transparency of ATC Calculations.** The absence of a consistent methodology to determine available transfer capability (ATC) provides discretion to transmission providers to deny service to competitors. The Commission proposes to make certain elements of ATC more consistent, and directs public utilities, working through the North American Electric Reliability Council, to address identified areas of concern. It also increases the transparency of ATC calculations through additional pro forma OATT requirements and postings on the open-access same-time information systems (OASIS) required under Order No. 889.
- **Transmission Planning, Regional Coordination And Transparency.** Vertically integrated utilities lack the incentive to relieve transmission constraints in a nondiscriminatory manner, and existing planning processes lack transparency, each of which contributes to potential undue discrimination in, and otherwise creates barriers to, infrastructure development. The Commission proposes to require transmission providers to participate in an open and transparent regional transmission planning process that adheres to the NOPR's planning principles.
- **Transmission Pricing.** The Commission proposes to reform pricing policies related to imbalances, credits for customer-owned transmission facilities and capacity reassignment.
- **Increased Transparency.** In addition to the ATC and planning reforms, the Commission proposes to require transmission providers to post all business rules, practices and standards on OASIS, and to include credit review procedures in their OATT. The NOPR also would require transmission providers and network customers to use the OASIS to request designation of a new network resource and to terminate the designation of an existing resource.

The FERC states that the NOPR retains the use of functional unbundling in conjunction with the OATT to promote competitive wholesale power markets and reduce barriers to market entry through the control of transmission, but does not impose any particular market structure on the industry.

FERC Notice of Proposed Rulemaking³², Feb. 2, 2006 - "New Guidelines For Long-Term Firm Transmission Rights In Organized Energy Markets Proposed By Commission" (Docket Nos. RM06-8-000 and AD05-7-000)

The EPAct 2005, Section 1233, added a new section 217 to the Federal Power Act (FPA). As a result the FERC is proposing to amend its regulations to require each transmission organization that is a public utility with one or more organized electricity markets to make available long-term firm transmission rights that satisfy the NOPR's proposed guidelines.

The FERC proposes guidelines for the design and administration of long-term firm transmission rights that transmission organizations with organized electricity markets would make available to all transmission customers. The FERC states that it will allow regional flexibility in setting the terms of the rights, but long-term firm transmission rights must be made available with terms (and/or rights to renewal) that are sufficient to meet the needs of load-serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. While we propose that long-term firm transmission rights be made available to all transmission customers, in the event that a transmission organization cannot accommodate all requests for long-term firm

³² FERC NOPR

transmission rights over existing transmission capacity, FERC proposed to require that a preference be given to load-serving entities with long-term power supply arrangements used to meet service obligations.

FERC believes that the new guidelines will give transmission organizations, in consultation with market participants, the flexibility to propose alternative designs that reflect regional preferences and accommodate the regional market design, while also ensuring that the objectives of Congress expressed in new section 217(b)(4) of the FPA are met.

The NOPR proposal sought comments on the following eight guidelines³³:

- The long-term firm transmission right should specify a source (injection node or nodes) and sink (withdrawal node or nodes), and a quantity.
- The long-term firm transmission right must provide a hedge against day ahead locational marginal pricing congestion charges (or other direct assignment of congestion costs) for the period covered and quantity specified. Once allocated, the financial coverage provided by the right should not be modified during its term except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the transmission organization.
- Long-term firm transmission rights made feasible by transmission upgrades or expansions must be available upon request to any party that pays for such upgrades or expansions in accordance with the transmission organization's prevailing cost allocation methods for upgrades or expansions. The term of the rights should be equal to the life of the facility (or facilities) or a lesser term requested by the party paying for the upgrade or expansion.
- Long-term firm transmission rights must be made available with terms (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term.
- Load-serving entities with long-term power supply arrangements to meet a service obligation must have priority to existing transmission capacity that supports long-term firm transmission rights requested to hedge such arrangements.
- A long-term transmission right held by a load-serving entity to support a service obligation should be re-assignable to another entity that acquires that service obligation.
- The initial allocation of the long-term firm transmission rights shall not require recipients to participate in an auction.
- Allocation of long-term firm transmission rights should balance any adverse economic impact between participants receiving and not receiving the right.

³³ FERC Feb. 2, 2006 press release

The FERC is currently evaluating the comments and reply comments to the NOPR.

FERC Notice of Proposed Rulemaking³⁴, Nov. 18, 2005 - “Promoting Transmission Investment through Pricing Reform” (Docket No. RM06-4-000)

The EPAct 2005, Section 1241 (Transmission Infrastructure Investment) adds a new section 219 to the Federal Power Act (FPA) which mandates that not later than one year after enactment of section 219, the FERC to establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. FPA section 219 was implemented against the backdrop of declining investment in transmission infrastructure and increasing electric load.

To address the need for new transmission infrastructure and to encourage necessary investment, the new section 219 specifically charges the Commission with the responsibility to establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce that:

- Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;
- Provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);
- Encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and
- Allow the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards established pursuant to section 215 of the FPA, and all prudently-incurred costs related to transmission infrastructure development, pursuant to section 216 of the FPA (transmission national interest corridors).

Included among the incentives proposed for all jurisdictional utilities, including transcos, are³⁵:

- Providing a rate of return on equity sufficient to attract new investment;
- Recovery in rate base of 100 percent of prudent transmission-related construction work in progress, in order to increase cash flow;
- Expensing prudent pre-commercial operation costs instead of capitalizing them, allowing for immediate cash flow for the utility;

³⁴ FERC NOPR

³⁵ FERC Nov. 17, 2005 press release

- Allowing hypothetical capital structures to provide the flexibility needed to maintain the viability of new capacity projects;
- Accelerating recovery of depreciation expense;
- Recovering all prudent development costs in cases where construction of facilities may be abandoned or canceled due to circumstances beyond the control of the utility;
- Allowing deferred cost recovery; and
- Providing a higher rate of return on equity for utilities that join transmission organizations.

To receive an incentive-based rate of return on equity, a public utility must demonstrate that the new facilities would improve regional reliability and reduce transmission congestion. In addition, the public utility must explain if the planned facilities are part of a regional planning process, how the proposed return on equity was derived and why it is appropriate.

The proposed rules also allow for recovery of costs associated with (1) joining a transmission organization; (2) electric reliability organizations; and (3) infrastructure development in National Interest Transmission Corridors identified by the Department of Energy pursuant to the Energy Policy Act.

The FERC is currently evaluating the comments and reply comments to the NOPR.