BUILDING A WORLD OF DIFFERENCE®

NEW YORK INDEPENDENT SYSTEM OPERATOR

Rate Schedule 1 Study
Status Update

Review of Other ISO/RTO's

March 2011

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1.0 RATE STRUCTURES AT OTHER ISO'S/RTO'S

System Operators in the United States reflect varying stages of cost unbundling in the rates they charge to their respective market participants. For comparative purposes, Black & Veatch reviewed the rate structures for ISO New England (ISO-NE), PJM, California ISO (CAISO), ERCOT, Midwest ISO (MISO) and Southwest Power Pool (SPP).The current rate designs at ISOs/RTOs vary from a fully bundled single rate (ERCOT) to the multiple schedules used by California ISO. Each of the ISO/RTOs has attempted to involve stakeholders, to varying degrees, while developing new rate changes. A brief description of their rates is shown below. All capitalized terms have the same meaning as that stated in their tariffs.

1.1 PJM

The PJM tariffs were developed in a collaborative process with a group of market participants. However, the ultimate approved tariffs resulted from settlement discussions initiated after the initial FERC application. The current PJM schedules include:

1.1.1 Schedule 9-1 - Control Area Administration Service

Control Area Administration Service comprises all of the activities of PJM associated with preserving the reliability of the PJM Region and administering Point-to-Point Transmission Service and Network Integration Transmission Service. PJM provides Control Area Administration Service to customers using Point-to-Point or Network Integration Transmission Service under this Tariff.

PJM charges each user of Control Area Administration Service a monthly charge equal to the Monthly Control Area Administration Service Rate of $0.1750 per MWh times the total quantity in MWhs of energy delivered (including losses) during a month.

1.1.2 Schedule 9-2 - FTR Administration Service

FTR Administration Service comprises all of the activities of PJM associated with administering the Financial Transmission Rights (FTR) provided for under Attachment K to the Tariff, including, but not limited to, coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's on-line, Internet-based eFTR tool, and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at a given time. PJM provides this service to entities that hold FTRs or entities that submit offers to sell or bids to buy FTRs.

PJM charges each user of Financial Transmission Rights Administration Service each month a charge equal to:

(i) The FTR Service Rate, $0.0026 per MWh, times the quantity in megawatts of all FTRs held by the user in each hour of the month, summed for each hour that the user holds FTRs during the month and time period the FTR is in effect; plus

(ii) The FTR Service Rate, $0.0018 per hour, times the sum of (1) the number of hours in all bids to buy Financial Transmission Rights Obligations submitted by the user during the month, plus (2) five times the number of hours in all bids to buy Financial Transmission Rights Options submitted by the user during each month.

1.1.3 Schedule 9-3 - Market Support Service

Market Support Service comprises all of the activities of PJM associated with supporting the PJM Interchange Energy Market and related functions, as described in Schedule 1 of the Operating Agreement and the Appendix to Attachment K to the Tariff, including, but not limited to, market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, support of PJM's Internet-based customer interactive tool known as eSchedules, and market monitoring. PJM provides this service to

customers using Point-to-Point or Network Integration Transmission Service, Generation Providers and entities that submit offers to sell or bids to buy energy in the PJM Interchange Energy Market.

PJM charges each user of Market Support Service each month a charge equal to the sum of:

(i) The MS Service Rate, $0.0386 per MWh times (1) the total quantity in MWhs of energy delivered to load (including losses and net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region or for export from the region during the month by Point-to-Point Transmission Service or Network Integration Transmission Service customers, plus (2) the total quantity in MWhs of energy input into the Transmission System by a Generation Provider plus (3) the total quantity in MWhs of all accepted Increment Bids and Decrement Bids submitted by the customer during the month; plus

(ii) The MS Service Rate Component 2, $0.0577 per Bid/Offer Segment times the number of Bid/Offer Segments submitted by the user during the month.

1.1.4 Schedule 9-4 - Regulation and Frequency Response Administration Service

Regulation and Frequency Response Administration Service comprises all of the activities of PJM associated with administering the provision of Regulation and Frequency Response Service under Schedule 3 of the Tariff. PJM provides this service to Load Serving Entities and to generators that provide regulation in accordance with Schedule 3.

PJM charges each user of Regulation and Frequency Response Administration Service each month a charge equal to the Regulation and Frequency Response Administration Service Rate, $0.2349 per MWh times the MWhs of the user's hourly regulation objective as a Load Serving Entity determined pursuant to Schedule 3, plus the MWhs of regulation scheduled (including self-scheduling) from generating units owned by the user, summed for each hour in the month.

1.1.5 Schedule 9-5 - Capacity Resource and Obligation Management Service

Capacity Resource and Obligation Management (CROM) Service comprises the activities of PJM associated with (i) assuring that customers have arranged for sufficient generating capacity to meet their unforced capacity obligations under the Reliability Assurance Agreement (RAA); (ii) processing Network Integration Transmission Service; (iii) administering the Reliability Pricing Model auctions for the PJM Region; and (iv) administering or providing technical support for the RAA (as delegated to PJM under the RAA), including, but not limited to, long-term load forecasting, studies to establish reserve requirements, and the determination of each Load-Serving Entity's capacity obligations. PJM's eCapacity Internet-based tool enables many of these functions. PJM provides this service to Load-Serving Entities and to owners of Capacity Resources.

PJM charges each Load-Serving Entity in the PJM Region a monthly charge equal to the Capacity Resource and Obligation Management Service Rate, $0.0894 per MW-day, times the summation for each day of the month of the Daily Unforced Capacity Obligation of each user.

1.1.6 PJM Cost Recovery From Load and Supply

The following table shows the percentage of PJM's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both.

Table 1-1
PJM Cost Recovery

Rate	Percent of Revenue Requirement	Load	Supply	Billing Determinants
9-1 Control Area Administrative Service	58%	100%	0%	MWh of load
9-2 FTR Service	5%	50%	50%	MWh of FTRs held
9-3 Market Support Service	30%	50%	50%	MWh of load and gen
9-4 Regulation & Frequency Response Administration	2%	50%	50%	MWh of hourly regulation required and provided
9-5 Capacity Resource & Obligation Management	5%	50%	50%	MW days of capacity required and provided
Composite Percentage		**79%**	**21%**	

Source: Suzanne Daugherty, PJM CFO, input per PJM Tariff Schedules 9-1 through 9-5

1.2 ISO-New England

The ISO-New England (ISO-NE) Tariffs were developed by ISO-NE and then modified based on Settlement discussions before FERC.

ISO-NE has three separate rate schedules (as listed below) designed to recover the ISO-NE's operating costs on a forecast basis, based on its annual budget, with a true-up mechanism to ensure no over or under recovery of the ISO-NE's actual operating expenses. The basic rate design was implemented in 1999. Below is the brief description of three rate schedules contained in the ISO tariff.

1.2.1 Schedule 1 – Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. This schedule provides for the assessment of charges designed to recover the ISO-NE's costs associated with performing administrative functions and tasks relating to scheduling transmission service and dispatching the transmission system. These ISO's expenses are based on the functions and activities required to provide this service and include:

- Processing and implementation of requests for transmission service, including support of OASIS Node
- Coordination of transmission system operation, including administration of reactive power requirements and implementation of necessary control actions by the ISO and support for these functions
- Billing associated with regional transmission services provided under the tariff
- Transmission System Planning
- Administrative support for the above tasks and functions

The Schedule 1 rates are as follows:

a) Each Customer that is obligated to pay the Regional Network Service rate will pay each month the product of $0.12683 per kilowatt month times its regional Monthly Network Load for that month;

b) Each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction scheduled to occur during the month as Through or Out Service multiplied by $0.00017 per kilowatt for each hour of service.

1.2.2 Schedule 2 – Energy Administration Service

This schedule provides for the assessment of charges designed to recover the ISO-NE's costs associated with administering the Energy Market. The functions and tasks performed by the ISO-NE include:

- Core operation of the Energy Market
- Generation and demand dispatch related to the Energy Market
- Energy Accounting
- Loss determination and allocation
- Billing preparation
- Market power monitoring and mitigation for the Energy Market
- Sanction activities
- Operation of Financial Transmission Rights (FTR) auctions
- Market assessments and reports
- Formulation of additional Market Rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO will pay a monthly amount based on Energy Transaction Units (TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

1. Energy TU Based Charges: Each customer will pay sum of the products of:
    a. $0.55449 times the Customer's first 12,500 Energy TUs for that month; plus
    b. $0.50408 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus
    c. $0.45367 times the amount of Energy TUs that exceed 39,500.

2. Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids will pay, amounts equal to:
    a. $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus
    b. $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.
3. Volumetric Measure (VM) Based Charges: A Customer shall be considered an Energy Administration Service (EAS) VM Customer if the sum of Monthly Real-Time Load Obligation and Monthly Real-Time Generation Obligation (measured in megawatt hours, MWh) assessed to that Customer during the month exceeds zero, in which case, the total EAS VM charges for that Customer will be equal to the sum of:
    a. Monthly Real-Time Load Obligation (MWh); and
    b. Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick Ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs.
4. Each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:
    1. $0.19333 per MWh for the first 250,000 MWh of EAS VM for that month; plus

2. $0.17575 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus
3. $0.15818 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

5. Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids will pay, amounts equal to:
   a. $0.60724 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus
   b. $0.60724 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions; plus
   c. $1.07903 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus
   d. $1.07903 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions.

1.2.3 Schedule 3 – Reliability Administrative Service (RAS)

This schedule provides for the assessment of charges designed to recover the ISO-NE's costs associated with administration of the Reliability Markets. The functions and tasks performed by the ISO-NE include:

- Generation Dispatch associated with Reliability Markets
- Reliability Markets accounting
- Billing preparation
- The ISO generation emissions analysis
- Risk profile updates
- Triennial review of resource adequacy
- Studies and qualification of resources under Forward Capacity Market
- Preparation of regional reports and load forecasts and profiles
- Support of power supply, environmental and market reliability planning activities
- Market power monitoring, mitigation and assessment of the Reliability Markets
- Formulation of additional Market Rules and proposals to modify existing rules

Each Transmission Customer taking Through or Out Service that is not a Market Participant will be considered a RAS Customer and will pay each month, a RAS fee equal to the product of $2.39 times the number of hourly Through or Out reservations made for that month.

Each Customer that is a Market Participant will be considered a RAS Customer and shall pay each month, an amount equal to the product of $0.14078 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

For Exports, each RAS Customer will pay each month, an amount equal to $0.31 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

1.2.4 True-Up Provision

For the Services described in Schedules 1, 2, and 3, deviations between collections and the ISO's actual expenses are reconciled through a year-to-year, prospective true-up. For example, before the close of calendar year 2010, the ISO will compute the total actual-to-date and projected-to-year-end expenses of providing each of those Services, and compare these totals with the total charges actually collected (and projected to be collected through 2010) under the Tariff for each Service during calendar year 2010. From these figures the ISO will calculate rates for calendar year 2011, and make a rate change filing for calendar year 2011 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and

the true-ups calculated by means of the analysis and adjustments. Any deviation between projected and actual true-up amounts for calendar year 2010 will be reflected in the rate changes for calendar year 2011.

1.2.5 ISO-NE Cost Recovery From Load and Supply

The following table shows the percentage of ISO-NE's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both.

Table 1-2
ISO-NE Cost Recovery

Rate	Percent of Revenue Requirement	Load	Supply	Billing Determinants
Schedule 1 - Scheduling Service	21%	100%		Charged to load: MWh and reserved capacity of the highest hourly amount during the month
Schedule 2 - Energy Administration Service	43%	50%	50%	Charged to load, gen, and FTR's: 15% based on energy, incremental and decremental changes, and FTR bids, 85% based on monthly load and gen. obligation
Schedule 3 - Reliability Administration Service	36%	100%		Charged to withdrawals: MWh of peak load and exports
Composite Percentage		**78%**	**22%**	

Source: ISO-NE 2009 FERC Form 1 and CAISO 2012 Cost of Service Study, p. 38

1.3 California ISO

Originally, the California ISO (CAISO) proposed the first charge to recover its cost of operations in a filing made on October 17, 1997 in Docket No. ER 98-211-000. The original Grid Management Charge (GMC) was a bundled formula rate. Following a settlement with stakeholders that extended the bundled rate through 2000 and gave rise to a stakeholder process to unbundle the GMC, the ISO proposed an unbundled GMC on November 1, 2000 that had three service charges: 1) the Control Area Services Charge; 2) Congestion Management (the Inter-Zonal Scheduling Charge); and 3) Ancillary Services (AS) and Real-time Energy Operations (the Market Operations Charge). Each charge was recovered through a volumetric (MWh) rate designed to recover the costs through related customer usage.

CAISO's rates have continued to evolve over time and are the most unbundled of any ISO/RTO rate design. The ISO's current GMC rate design was submitted to FERC in February 2008 and consisted of: 1) the elimination of the Congestion Management Charge; 2) modifications to the Core Reliability Services (CRS) and Energy Transmission Services (ETS) Charges to reflect flows on Transmission Ownership Rights (TORs); 3) changes in the billing determinants for Forward Scheduling (FS) and Market Usage (MU) Charges (including the introduction of the Market Usage-Forward Energy Charge (MUFE)); and 4) an increase in the SMCR Charge from $500 to $1,000. The proposal was approved by FERC on December 18, 2008 and went into effect on April 1, 2009.

1.0 RATE STRUCTURES AT OTHER ISO'S/RTO'S

CAISO currently has rates defined for the following categories:

- Core Reliability Services (CRS)
- Energy Transmission Services (ETS)
- Transmission Ownership Rights (TOR)
- Forward Scheduling (FS)
- Market Usage (MU)
- Convergence Bidding
- Settlements, Metering, & Client Relations (SMCR).

CAISO GMC Rates for 2011 with effective from January 1, 2011 is shown in Table 1-3.

Table 1-3
CAISO GMC Rates for 2011

#	Type	Rate	Billing Unit	Data
1.	CRS - Demand Charge	$75.8960	MW-mo	Non-coincident Peak - Maximum Hourly load (not including exports) within a month during the hours ending 07 through 22
2.	CRS - Demand Off Peak	$50.0999	MW-mo	Non-coincident Peak - Maximum Hourly load (not including exports) within a month during the hours ending 01 through 06 and 23 and 24.
3.	CRS - Energy Export	$1.6290	MWh	Export MWhs, excluding TOR exports
4.	ETS - NE	$0.2953	MWh	MWhs of Metered Balancing Authority Area Load, excluding TOR Metered Balancing Authority Area Load
5.	ETS - UE	$1.2225	MWh	MWhs of Uninstructed Imbalance Energy summed by interval, excluding PIRP UIE
6.	CRS/ETS-TOR Energy Export	$ 0.2266	MWh	MWhs of TOR Metered Balancing Authority Area Load
7.	Forward Scheduling	$1.3170	Non-zero MW Schedule	Number of Day Ahead and Hour Ahead Scheduling Process Load, Generation, Import, Export and awarded AS energy schedules
8.	Forward Scheduling Inter-SC Trade	$1.3170	Non-zero MW Inter SC trade schedule	Number of interSC trade schedules
9.	Forward Scheduling PGAB Inter-SC Trades	0.9956	Non-zero MW Inter SC trade schedule	Number of PG&E Path 15 Facilitator inter SC trade schedules
10.	MU-Awarded AS	0.4488	MWh	MWhs purchases and sales of AS
11.	MU-Instructed Energy	0.4488	MWh	MWhs of Instructed Energy summed by interval
12.	MU-Net Uninstructed Deviation	0.4488	MWh	MWhs of Uninstructed Imbalance Energy summed by interval, excluding PIRP UIE
13.	MU-Forward Energy	0.0494	MWh	Maximum MWh of an SC's Supply or Demand
14.	Convergence Bidding Fee	0.0050	Per bid segment	per bid segment of submitted convergence bids
15.	Convergence Bidding	0.0618	MWh	MWh of Convergence Bidding
16.	ETS/MU PIRP Deviations	1.6713	MWh	MWhs of Uninstructed Imbalance Energy from Participating Intermittent Resources summed during the month
17.	SMCR	1,000	Customer-month	For customers with non-zero market, PTO, or CRR invoice

Note: 1. The convergence bidding expected to go live on 2/1/11

1.3.1 True-Up Provision

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the CAISO's filing or posting on the CAISO Website if the estimated revenue collections for that component, on an annual basis, change by more than five percent (5%) or $1 million, whichever is greater, during the year. The adjustment may not be implemented more than once per calendar quarter, and will be effective the first day of the next calendar month.

1.3.2 CAISO Cost Recovery From Load and Supply

The following table shows the percentage of CAISO's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both. As shown in the table, the revenue requirement is recovered 67% from Load and 33% from Supply. This is the highest percentage recovered from Load of all the ISO/RTO's reviewed.

Table 1-4
CAISO Cost Recovery

Function	Rate Name	% of Rev Req	Load	Supply	Billing Determinant
Core Reliability Services (CRS)	CRS - Demand (peak)	17.0%	100%	0%	Monthly on peak NCP
	CRS - Demand (off peak)	0.5%	100%	0%	Monthly off peak NCP
	CRS - Energy export	4.4%	100%	0%	MW of exports, excluding exports on transmission ownership rights (TORs)
Energy Transmission Services (ETS)	ETS - net energy	36.2%	100%	0%	MWh of metered control area load, excluding load on TORs
	ETS - uninstructed deviations	6.2%	0%	100%	MWh of uninstructed imbalance energy (UIE) netted over the settlement interval
Transmission Ownership Rights	TOR	0.5%	100%	0%	MWh of metered control area load on TORs
Forward scheduling (FS)	FS	6.3%	50%	50%	Count of hourly schedules
	FS - interSC trades				Count of hourly trades
Market Usage (MU)	Purchase and sales of ancillary services (AS)	18.1%	0%	100%	Day ahead (DA) and hour ahead scheduling process real time (RT) MWh
	Instructed energy (IE) RT				MWH of IE
	Net uninstructed deviations - RT				MWh of UIE netted over the settlement interval
	Forward energy	8.4%	50%	50%	Maximum MWh of supply or demand scheduled in the DA market
Convergence bidding	Bid charge	1.5%	50%	50%	Bid charge of $0.005 per bid segment
	Volumetric charge				Gross amount of supply or demand awarded in the DA market
Settlements, metering & client relations (SMCR)	SMCR	0.9%	50%	50%	Monthly customer charge of $1,000 per business associate ID
Total		100%			
Composite Percentage			**67.1%**	**32.9%**	

Source: CAISO

1.4 Midwest ISO

The Midwest ISO (MISO) has three primary rates for recovery of its costs: Schedule 10 – ISO Cost Recovery Adder; Schedule 16, Financial Transmission Rights (FTR) Administrative Service Cost Recovery Adder; and Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder. There are some sub-categories to these schedules applicable to specific customers, but only the primary rates are discussed herein.

For all the rates, monthly charges are calculated based on budgeted costs and estimated MWhs of transmission service less the number of MWhs derived from the sub-categories. The charges change on a monthly basis and are trued up in the following month's calculation to reflect actual costs and actual MWhs of Transmission Service.

1.4.1 Schedule 10 - ISO Cost Recovery Adder

The cost recovery mechanism and charges in Part II of Schedule 10 are applicable to all Transmission Customers, Transmission Owners and Appendix I entities whose filings have been approved by the Commission. The costs recovered under this Schedule 10 include the costs associated with building and operating MISO's Security Center, including capital costs and operating expenses; and costs associated with administering the Tariff.

Rate Schedule 10 is a two-part rate, a "Reserved Capacity Rate" and an "Energy Rate". The Reserved Capacity Rate is multiplied by billing units of Reserved Capacity, and the Energy Rate is multiplied by billing units of MWhs of scheduled energy. In the rate calculations, 50% of the billing units used are based on MWhs of Reserved Capacity and 50% of the billing units are based on MWhs of Energy.

While the rate changes monthly and is trued-up to actuals, the range for the combined demand and energy rate in 2010 was from $0.1051/MWh to a high of $0.1691/MWh.

1.4.2 Schedule 16 - Financial Transmission Rights (FTR) Administrative Service Cost Recovery Adder

This FTR Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by the Transmission Provider, inclusive of all costs resulting from assignment or allocation of costs to the Service. The Transmission Provider's costs incurred in providing the Service include costs associated with:

1. Coordination of FTR bilateral trading;
2. Administration of FTRs through allocation, assignment, auction or any other process accepted by the Commission;
3. Support of the Transmission Provider's on-line, Internet-based FTR tool;
4. "Simultaneous feasibility" analyses to determine the total combination of FTRs and Option B GFA entitlements that can be outstanding and accommodated by the Transmission System at a given point in time; and,
5. Administration of FTRs and revenue distribution.

The billing determinants for the FTR Administrative Service Cost Recovery Adder equal the total amount of FTR volume for all FTR Holders and Option B GFA entitlements, expressed in MW. The total FTR volume equals the MW of FTR capacity in effect in each hour for all FTRs held during the applicable month. While the rate changes monthly and is trued-up to actuals, the range in 2010 was from $0.0109/MWh to a high of $0.0194/MWh.

1.4.3 Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder

This Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by a Transmission Provider, inclusive of all costs resulting from the assignment or allocation of costs to the Service. The Transmission Provider's costs incurred in providing the Service include costs associated with:

1. Market modeling and scheduling functions;
2. Market bidding support;
3. Locational marginal pricing support;
4. Market settlements and billing;
5. Market monitoring functions; and,
6. Simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the Midwest ISO Balancing Authority Areas while also establishing a spot energy market.

The billing determinants for the Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder are:

1. All Actual Energy Injections into the Transmission System by all Market Participants, including deliveries to the Transmission System from generation located both within the Transmission System and outside of the Transmission System,
2. All Actual Energy Withdrawals from the Transmission System by all Market Participants, including MWh delivered to loads located both within the Transmission System and outside of the Transmission System including all out and through transactions using the Transmission System; and,
3. All Bids or Offers for Energy that settle in the Day-Ahead Energy and Operating Reserve Market, but do not actually inject MWh into or extract MWh from the Transmission System in the Real-Time Energy and Operating Reserve Market.

While the rate changes monthly and is trued-up to actuals, the range in 2010 was from $0.0727/MWh to a high of $0.1125/MWh.

1.4.4 Midwest ISO Cost Recovery From Load and Supply

The following table shows the percentage of Midwest ISO's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both.

Table 1-5
Midwest ISO Cost Recovery

Rate	Percent of Revenue Requirement	Load	Supply	Billing Determinants
Schedule 10 - ISO Cost Recovery Adder	45%	100%		50% to MWh of load, 50% based on peak capacity for month
Schedule 16 - FTR Administrative Service Cost Recovery Adder	6%	100%		MW of FTR capacity
Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder	49%	50%	50%	MWh of gen, load, and virtual
Composite Percentage		**75%**	**25%**	

Source: Midwest ISO 2009 FERC Form 1 and CAISO 2012 Cost of Service Study, p. 38

1.5 ERCOT

ERCOT system administration fees are charged to market participants for use of ERCOT scheduling, settlement, registration and other related system and equipment. ERCOT has numerous other fees to recover cost of security screening, interconnection studies, map sales and copying. Table 1-6 below shows ERCOT fee schedule effective January 1, 2011:

Table 1-6
ERCOT Rates

Description	**Calculation/Rate/Comment**
ERCOT System Administration fee	$0.4171 per MWh to fund ERCOT activities subject to Public Utility Commission of Texas (PUCT) oversight. This fee is charged to all Qualified Scheduling Entities (QSEs) based on Load represented.
Other Charges	
ERCOT Security Screening Study	A preliminary study of the impacts of a proposed generation plant conducted by ERCOT staff - $1,000 (10MW to 74MW) $2,000 (75MW to 149 MW) $3,000 (150MW to 249MW) $4,000 (250MW to 499MW) $5,000 (500MW and above)
Full Interconnection Study	Costs incurred by the Transmission and/or Distribution Service Provider (TDSP) for completing a detailed study - $15 per MW (Not Refundable – to support ERCOT system studies and coordination)
Map Sale fees	$20 - $40 per map request (by size)
Qualified Scheduling Entity Application fee	$500 per Entity

Competitive Retailer Application fee	$500 per Entity
Mismatched Schedule Processing fee	$1 per mismatched event - Assessed to QSEs submitting schedules referencing each other where the schedules do not match
Voluminous Copy fee	$0.15 per page in excess of 50 pages

Ninety eight percent of ERCOT's revenue requirement is recovered from Load with the System Administration Fee. The remaining revenue requirement is recovered with the various charges shown in Table 1-5.

1.6 Southwest Power Pool

Southwest Power Pool (SPP) current tariffs includes following schedules:

1.6.1 Schedule 1 - Scheduling, System Control and Dispatch Services

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within or into a Control Area. The SPP Tariff shows both on peak and off peak rates for Schedule 1. Both the hourly on peak and off peak rates are shown as $0.1711/MWh.

Schedule 1 A: TARIFF ADMINISTRATION SERVICE:

The Transmission Provider provides Tariff Administration Service to carry out its Responsibilities. The Transmission Customer must purchase this service from the Transmission Provider. It includes:

1. **Administration Charge:**
   An administration charge is applied to all transmission service to cover the SPP's expenses related to administration of the Tariff. For Point- To-Point Transmission Service, this charge can be up to $0.225 per MW per hour for all capacity reserved. For Network Integration Transmission Service this charge can be up to $0.225 per MW per hour for the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.

   For each calendar year, the SPP establishes this administration charge by dividing projected expenses based on its budget for the calendar year divided by the projected annual Schedule 1-A billing units for the calendar year. SPP reconciles actuals to budgeted figures and shall adjust charges for the following calendar year to reflect either over or under recoveries of its costs for the prior year to allow it to recover its actual costs. In projecting and recovering its expenses, SPP recovers 100% of its total expenses through this charge up to the cap of $0.225 per MW per hour for all transmission service.
2. **Transmission Service Request Charges:**
   The Transmission Customer pays SPP a charge for each new Transmission Service Request as follows:
   a. For Firm Point-To-Point Transmission Service:
      Reservations less than one month: $100
      Reservations one month or longer: $200
   b. For Non-Firm Point-To-Point Transmission Service:
      Each Reservation: $0
3. **Bad Debt Expenses:**

SPP includes in its charges under this Schedule a component to cover estimated bad debts. The Transmission Provider reconciles actual results to estimates and adjusts future monthly charges to reflect either over or under recoveries.

The cost recovery for SPP market participants is 100 percent from Load.

1.7 Summary of Cost Recovery from Load and Supply

The following table summarizes the approximate cost recovery ratio from load and supply. Generally, the more unbundled the rates are (CAISO), the higher percentage of cost are recovered from supply. The most bundled rates (ERCOT and SPP) have the highest percentage of costs recovered from load.

Table 1-7
Summary of Cost Recovery from Load and Supply (1)

Company	Load Share %	Supply Share %
ERCOT	100%	0%
Southwest Power Pool	100%	0%
New York ISO (2)	80%	20%
PJM	79%	21%
ISO-New England	78%	22%
Midwest ISO	75%	25%
California ISO	67%	33%

Notes:
(1) Approximate current ratio based on contact with RTO/ISO staff and available published documents
(2) NYISO varies somewhat based on collections for TCCs, Virtuals, and Demand Response