An In-Depth Look at Regional Transmission Organizations and Independent System Operators for Lawyers and Energy Professionals

This seminar will explore many facets of organized markets in Regional Transmission Organizations and Independent System Operators in the United States. After an introduction to the world of RTOs and ISOs, panelists will discuss the fundamental underpinnings of and major issues arising out of energy and capacity markets, along with the controversy associated with compensation for demand response aggregators. The seminar will conclude with a look at how entities decide whether to join an RTO or ISO. FERC Commissioner John Norris will address attendees during the luncheon.

<table>
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<th>PROGRAM SCHEDULE</th>
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| **WEDNESDAY, APRIL 25, 2012** | **9:30** - Energy Markets  
11:00 a.m. |

This panel will explore the fundamental underpinnings of energy markets. Panelists will explain the purpose and inter-related functions of day-ahead, real-time, ancillary services and congestion markets. They will address the concept of locational marginal pricing, and the way RTOs and ISOs use these markets to promote market efficiency and grid reliability.

Moderator: F. Stuart Bresler III  
Market Operations and Demand Resources  
PJM Interconnection, L.L.C.

Speakers: Richard Tabors  
Vice President  
Charles River Associates

Sean A. Atkins  
Partner  
Alston & Bird LLP

David B. Patton  
President  
Potomac Economics

| **8:00 a.m.** | **REGISTRATION** |
| **8:20 a.m.** | **WELCOME AND INTRODUCTION** |
| Derek A. Dyson  
President, Energy Bar Association  
Duncan, Weinberg, Genzer & Pembroke, P.C. |

| **8:30 - 9:15 a.m.** | **RTOs and ISOs: An Introduction** |

We start the day with a review of the nuts-and-bolts of Independent System Operators and Regional Transmission Operators, covering the history, governance, basic market structures, oversight and jurisdiction of ISOs and RTOs, along with the substance and impact of foundational FERC orders. The presentation will be an excellent introduction to ISOs/RTOs and will give context to the topical panels to follow.

Moderator: Marjorie R. Philips  
ISO Services Director  
Hess Corporation

Speakers: Cynthia A. Marlette  
Special Counsel  
Patton Boggs LLP

David T. Doot  
Partner  
Day Pitney LLP

| **11:15 a.m.** | **BREAK** |
11:15 a.m. - **Demand Response**

Panelists will discuss the advent of demand response, FERC’s Order 745 requirements for RTO/ISO development of demand response participation in the energy markets and the different approaches RTOs and ISOs have taken to compliance.

**Moderator:** Ryan Hledik  
Senior Associate  
The Brattle Group

**Speakers:**  
Nancy E. Bagot  
Vice President, Regulatory Affairs  
Electric Power Supply Association

Allen Freifeld  
Senior Vice President of  
External Affairs  
Viridity Energy

Steve Sunderhauf  
Manager, Program Evaluation  
Pepco Holdings, Inc.

12:30 - **LUNCHEON AND LUNCHEON SPEAKER**

**Introduction:** Derek A. Dyson  
President, Energy Bar Association  
Duncan, Weinberg, Genzer, & Pembroke, P.C.

**Speaker:**  
The Honorable John R. Norris  
Commissioner  
Federal Energy Regulatory Commission

2:15 - **Capacity Markets**

This panel will discuss current issues facing RTO/ISO capacity markets, including proper incentives for generation supply, impact on rates, battles with state initiatives to reduce capacity costs and minimum offer requirements, and self supply issues. The panel will also provide a brief overview of capacity market design and the capacity market’s role in maintaining system reliability.

**Moderator:** Stuart A. Caplan  
Partner  
SNR Denton US LLP

Paul M. Flynn  
Shareholder  
Wright & Talisman, P.C.

Glen R. Thomas  
President  
PJM Power Providers Group

Jay A. Morrison  
Senior Regulatory Counsel  
National Rural Electric Cooperative Association

Ted J. Murphy  
Partner  
Hunton & Williams LLP

3:45 - **BREAK**

4:00 - **Choosing a RTO or ISO**

The last panel of the day will explore the decision whether to join a RTO/ISO, what motivates a market participant to switch from one RTO/ISO to another, growing competition between RTOs/ISOs, and the issues caused when major market participants switch between RTOs/ISOs.

**Moderator:** Matthew R. Rudolphi  
Duncan, Weinberg, Genzer & Pembroke, P.C.

**Speakers:**  
Heather H. Starnes  
Manager, Regulatory Policy  
Southwest Power Pool, Inc.

John S. Moot  
Skadden, Arps, Slate, Meagher & Flom LLP

Grace C. Wung  
Assistant General Counsel  
NV Energy, Inc.

Lori Spence  
Deputy General Counsel  
Midwest ISO
RTOs and ISOs:
An Introduction
History and Overview of Independent System Operators and Regional Transmission Organizations

Presented by Cynthia A. Marlette
Special Counsel, Patton Boggs, LLP
Energy Bar Association
Washington, D.C.
April 25, 2012
A Snapshot of the U.S. Electric Industry in the Early 1990’s

- Electric industry dominated by vertically integrated investor-owned utilities with market power.
- Power pools – tight pools (e.g., NE, NY, PJM); loose pools (e.g., MAPP).
- Multi-state holding companies.
- Regional transmission groups (RTGs): voluntary organizations of transmission owners, users and other entities interested in coordinating transmission planning and expansion, operation and use of grid on a regional and interregional basis.
- Emerging competition in wholesale power markets. Non-traditional power suppliers; market-based rates.
- Voluntary open access transmission tariffs in exchange for FERC blanket authorization of market-based rates for wholesale sales of electric energy or FERC merger approval.
Mandatory Open Access: FERC Order No. 888 (1996)

- Goal: Eliminate undue discrimination/undue preference in transmission services by public utility transmission providers; promote competitive wholesale power markets.

- Mandatory non-discriminatory open access transmission tariffs (OATTs) for wholesale transmission and unbundled retail transmission; the golden rule of “comparability” in use of the grid.

- Functional unbundling by public utility transmission providers:
  - Transmission providers must take transmission and ancillary services for their own needs under the same OATT that applies to other users.
  - Separately stated rates for wholesale generation, transmission and ancillary services.
  - Transmission providers must use the same electronic information system (OASIS) as other customers for obtaining transmission system information (e.g., price and availability).
  - Standards of conduct: mandatory separation of transmission personnel and wholesale power merchant function personnel.
Mandatory Open Access:  
FERC Order No. 888 (1996)  
(continued)

• OATTs must contain minimum terms and conditions of transmission service and include: network, load-based service; and point-to-point, contract-based service.

• Power pools and holding companies required to file single system-wide OATT; elimination of rate pancaking.

• No corporate restructuring required, but encouragement of voluntary independent system operators (ISOs).

• Reciprocity condition for non-public utilities taking advantage of public utility OATTs.

• Stranded cost recovery.
What is an ISO?

- Order No. 888 adopts 11 principles for assessing proposals to create independent entities to operate jurisdictional transmission facilities:

1. **Governance** is structured in a fair and non-discriminatory manner, to ensure fair and non-discriminatory access to transmission and ancillary services; independent of any market participant or class of participants; fair representation of all types of users; no control over decision-making by any class of participants.

2. **No financial interest** by ISO or its employees in the economic performance of any power market participant. No ownership by any market participant. Strict conflict of interest standards.

3. **Provides open access to the transmission system** and all services under its control, at non-pancaked rates, under a non-discriminatory grid-wide tariff.

4. **Primary responsibility for ensuring short-term reliability of grid operations.**
What is an ISO?  
(continued)

5. Controls operation of interconnected facilities within its region.

6. Identifies constraints and is able to take operational actions to relieve constraints, within the governing body’s trading rules.

7. Incentives for efficient management and administration.

8. Transmission and ancillary services pricing policies that promote efficient use of and investment in generation, transmission, and consumption.

9. Operates an electronic information network by which to make transmission system information publicly available on a timely basis.

10. Coordinates with neighboring control systems.

11. Has an alternative dispute resolution process (ADR).
The Early ISOs

- ISO membership an effective way for individual utilities to comply with Order No. 888. (ISOs other than ERCOT are public utilities.)

- Order No. 888 requirement for pools to have system wide tariffs and depancaked rates provides strong incentive for tight pools to form early ISOs: PJM, NY, NE.

- State mandates serve as drivers of ISOs in some regions: Cal ISO, ERCOT. MISO a voluntary “new” institution.

- FERC flexibility to public utilities and states re. organizational form of ISOs (non-profit, for-profit transco, gridco, or hybrid form) and governance structure of ISOs. But “bedrock” principle of independence.

- Early ISO variations:
  - Governance variations: e.g., two-tier with independent non-stakeholder board on top, advised by one or more stakeholder groups; or hybrid board consisting of stakeholders and non-stakeholders. Key is to ensure that IOUs cannot dominate board or advisory committees.
  - Variations re. operational responsibilities; geographic scope; and centralized energy markets (real-time; hour-ahead; day-ahead).
A New Name “RTOs”
and FERC Order No. 2000 (1999)

• Impetus for RTOs: wholesale and retail restructuring activity following Order No. 888; heavier and different uses of the transmission grid; residual undue discrimination in transmission services.

• Order No. 2000 goals:
  – improve efficiencies in grid management
  – improve grid reliability
  – eliminate residual undue discrimination and undue preference in transmission services
  – improve market performance
  – facilitate lighter-handed regulation
What is an RTO?

• Order No. 2000 defines an RTO as an entity that satisfies 4 minimum characteristics, performs 8 minimum functions, and satisfies an open architecture requirement.

• Minimum characteristics:
  1. Independence
  2. Scope and regional configuration
  3. Operational authority
  4. Short-term reliability
What is an RTO?
(continued)

- Minimum functions:
  1. Tariff administration and design
  2. Congestion management
  3. Parallel path flow
  4. Ancillary services
  5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
  6. Market monitoring
  7. Planning and expansion
  8. Interregional coordination
RTO Flexibility

- Flexibility as to RTO structural form: ISOs; transcos; combinations of the two; or new organizational forms.
- No fixed regional boundaries, but RTO must serve a region of sufficient scope and configuration to maintain reliability and support efficient, non-discriminatory power markets. Emphasis on broad regional scope.
- Open architecture: RTOs must have flexibility to improve in terms of structure, operations, market support and geographic scope to meet market needs.
- Flexible transmission ratemaking for RTOs, including rates to address congestion pricing and performance-based regulation. Case-by-case incentive pricing for facilities under RTO control.
- A “voluntary” approach; ratemaking carrots.
- Encourages public power and other non-public utilities to participate.
Today’s RTOs

- All are subject to FERC-approved reliability standards.
- All are non-profit organizations.
- Varied governing structures:
  - unaffiliated board plus management committee composed of representatives of each party to the ISO (five industry sectors);
  - independent non-stakeholder board plus members committee to advise board (five voting sectors);
  - independent board plus advisory committees including a stakeholder participants committee;
  - independent board plus advisory stakeholder committee;
  - board nominated by state governor, confirmed by state senate; board nominee committee comprised of stakeholders from six sectors;
  - hybrid board composed of independents, consumer reps and from each market segment.
Today’s RTOs
(continued)

- Varied scope of market operations and market rules: auction-based energy markets; ancillary services markets; forward capacity markets.
- Performance metrics to track performance of ISO/RTO operations and markets in delivering benefits to consumers. Designed to track performance as to market benefits, organizational effectiveness and reliability.
- RTOs – evolving organizations; continual work in progress.
Increasing Role of the RTO Market Monitor

- FERC Order No. 719 (2008) – Increased independence of the MMU:
  - Internal v. external MMUs; or hybrid.
  - Report directly to RTO or ISO board, or to committee of the board, rather than management.
  - Access to data, resources, and personnel necessary to perform monitoring.
  - Removed from tariff administration.
  - Protocols for referrals to FERC staff of market design flaws and suspected market manipulation/wrongdoing.
  - Required quarterly reports and annual report on state of the market; regular conferences among MMU, RTO/ISO staff, FERC staff, interested state PUCs/AGs, market participants.
  - Procedures to share information with states.
  - Ethics standards for MMU and its employees.

- FERC ex parte restrictions apply to MMUs.
RTOs and ISOs: Regulation, Market Structure and Operations

presented to
Energy Bar Association
April 25, 2012
FERC Statutory Authority – FPA and the Filed Rate (backdrop)

- RTOs and ISOs are public utilities.
- Public utilities are required under § 205 of the FPA to have on file with FERC their rates, terms and conditions of electric services rendered with their jurisdictional assets – the “Filed Rate”
- Utilities may agree to delegate responsibility and rights to make such § 205 filings to another entity such as an RTO or ISO
- FERC can accept or approve the Filed Rate, reject it as unlawful, or accept it with changes, subject to refund if desired.
FERC Statutory Authority – FPA and the Filed Rate (cont.)

- The FPA requires that rates, terms and conditions for wholesale power and transmission be “just, reasonable and not unduly discriminatory or preferential”
- FERC is statutorily required to ensure that result
- Concerns with the Filed Rate must be remedied under § 206 of the FPA
  - FERC reconsiders appropriateness of Filed Rate or considers its interpretation or application
  - FERC cannot order changes to the Filed Rate without determining first that existing rates or practices fail to satisfy the requirements of the FPA
FERC Statutory Authority – FPA and the Filed Rate (cont.)

• Under § 203 of the FPA, a public utility must obtain FERC authorization prior to selling, leasing, or otherwise disposing of its jurisdictional facilities (subject to thresholds amounts not relevant for this discussion)

• ISO/RTO formation raised issues of interpretation of the meaning of “disposition” of facilities for purposes of § 203
FERC Exercise of its Authority Over ISOs and RTOs

- FERC relied upon its authority under §§ 205 and 206 to issue Orders 888 and 2000 which set forth the framework for the voluntary formation of ISOs and RTOs.
- There are, however, limits to the jurisdiction FERC can assert over ISOs and RTOs.
- Cases arising out of early ISO and RTO formation efforts tested and clarified fundamental jurisdictional boundaries under §§ 203 and 205.
Testing FERC Jurisdictional Limits (Atlantic City)

• The Atlantic City cases arise from challenges to FERC orders addressing PJM restructuring (ISO) proposal
  - Atl. City Elec. Co. v. FERC, 329 F.3d 856 (D.C. Cir. 2003) (“Atlantic City II”)

Testing FERC Jurisdictional Limits (Atlantic City) (background)

- In response to Order 888, Transmission Owners (TOs) proposed in 1996 to form PJM as an ISO to administer operation of the transmission network.
- FERC conclude that PJM restructuring was a "disposition of jurisdictional facilities" requiring FERC approval under FPA § 203.
- FERC rejected the initial restructuring proposal under § 205 as not satisfying the Order 888 ISO principles.
- TOs challenged jurisdictional finding in Court.
Testing FERC Jurisdictional Limits
(*Atlantic City*) *(background) (cont.)*

- Revised PJM proposal filed (June 1997)
  - Pool-wide transmission service
  - Tariff administration, regional transmission planning and operations transferred to the PJM
  - TOs reserved right to file changes in transmission service rate design and non-rate terms and conditions to the tariff under § 205, subject to limitations
  - TOs reserved the right to withdraw under certain circumstance upon 90 days’ notice without FERC approval
- FERC conditionally accepted the 1997 proposal, subject to certain modifications (intended to preserve independence principles)
  - TOs directed to eliminate provision allowing them to unilaterally file changes in rate design, terms or conditions of jurisdictional services
  - TO directed to provide that withdrawal must require FERC approval
- TOs challenge required modifications in Court
Testing FERC Jurisdictional Limits (Atlantic City I) (key RTO/ISO holdings)

- DC Circuit disagrees with FERC
  - Changes to the filed rate
    - FERC may not require a public utility to surrender its rights to file changes to its filed rate – the right to file is expressly granted in (and protected by) § 205
    - FERC has no authority to force public utilities to file particular rates unless it first finds the existing filed rates unlawful
    - FERC’s Order would have denied PJM TOs a right § 205 was designed to protect
  - No jurisdiction under FPA § 203
    - No “disposition” occurs when a utility agrees to the changes in operational control necessary to join or withdraw from an ISO
Testing FERC Jurisdictional Limits – Take Two (Atlantic City II)

- FERC Order on Remand
  - Directed PJM TOs to re-justify proposed allocation of filing responsibilities
  - Continued “to find that the withdrawal of a [TO] from the ISO … is a disposition of facilities necessitating … the [FERC's] prior review” under § 203

- DC Circuit again disagrees with FERC
  - FERC still has no jurisdiction to require utilities to surrender their rights under FPA § 205 to make filings to initiate rate changes
  - FERC still cannot require approval under FPA § 203 before a public utility can join or withdraw from an ISO
The Aftermath of Atlantic City Cases – 
TO Withdrawal From RTO/ISOs

• Withdrawals of TOs from an RTO/ISO will be reviewed and evaluated in context of § 205 filings

• 3-Prong test
  ▶ Departing TO must satisfy contractual withdrawal obligations
  ▶ New arrangement must comply with Orders 888 and 890
  ▶ Replacement arrangement must pass muster under § 205

• Impact on other market participants and the markets will be evaluated
The Aftermath of Atlantic City Cases – TO Withdrawal From RTO/ISOs (cont.)

• Examples


   - *Duquesne Light Co.*, 122 FERC ¶ 61,039 (2008) (allowed to withdraw from PJM to join MISO)

   - *FirstEnergy Serv. Co. v. PJM Interconnection*, 129 FERC ¶ 61,249 (2009) (allowed to withdraw from PJM to join MISO)

RTO Market Structure and Operations

RTO Market Rules Generally

- Market Rules filed by ISOs and RTOs under 205
- All Market Participants must comply with Market Rules as a condition to market-based rate authority (18 C.F.R. 35.41(a))
RTO Market Structure and Operations
Market Components Sold – Energy

- kWh or MWh
- “Negawatt hours” - pay customer not to consume at times when system is most stressed
- Prices are locational
- Prices vary by location (LMP)
- Prices can be hedged through FTRs, CRRs, CTRs, FCRs
- Revenues from hedge instruments may be sold at auctions conducted under tariff (Auction Revenue Rights) and transferred
RTO Market Structure and Operations
Market Components Sold – Capacity

• MW-month or -day or KW-month or -day
• Recognizes that, with limits on energy prices, a separate revenue stream is required to support resources needed for reliability
• Demand response resources can provide capacity for reliability
RTO Market Structure and Operations
Market Components Sold – Ancillary Services

- Operating Reserve - $/MW
- VAR - $/kV Amperes
- Automatic Generation Control
- Regulation
- Black Start
Market Components – Wholesale Cost %

- Energy: 74.51%
- Capacity: 15.39%
- Transmission: 7.04%
- Ancillary Services: 2.61%
- RTO Admin: 0.45%

http://www.pjm.com/~media/committees-groups/committees/mc/20120221/20120221-reports-item-03a-markets-report.ashx
Other Landmark Orders Affecting ISOs and RTOs

• Wholesale Competition (Order 719)
  ► RTO/ISO responsiveness
  ► Market-monitoring policies
  ► Pricing during periods of operating reserve shortage
    (demand response and energy market)
  ► Long-term power contracting

• Credit Reforms (Order 741)
• Demand Response Compensation (Order 745)
• Frequency Regulation (Order 755)
• Surveillance of Market Data (Order 760)
Other Landmark Orders Affecting ISOs and RTOs

- Transmission Planning and Cost Allocation (Order 1000)
- OATT Reform (Order 890)
- Long-Term Firm Transmission Rights (Order 681)
- Business Practice and Communication Protocol Standards (Order 676)
- Accounting and Financial Reporting (Order 668)
- Interconnection Queue Reform (AD08-2)
- Standard Market Design (RM01-12)
Questions?
NOTES
Energy Markets
Energy Markets

Energy Bar Association
ISO / RTO Seminar

April 25, 2012
PJM as Part of the Eastern Interconnection

- 26% of generation in Eastern Interconnection
- 28% of load in Eastern Interconnection
- 19% of transmission assets in Eastern Interconnection

KEY STATISTICS
- PJM member companies: 750+
- Millions of people served: 60
- Peak load in megawatts: 163,848
- MWs of generating capacity: 185,600
- Miles of transmission lines: 65,441
- GWh of annual energy: 832,331
- Generation sources: 1,365
- Square miles of territory: 214,000
- Area served: 13 states + DC
- Internal/external tie lines: 142

21% of U.S. GDP produced in PJM

As of 1/4/2012
PJM’s Operational Markets

- Day-Ahead Energy Market (June 1, 2000)
- Real-Time Energy Market (April 1, 1997)
- Capacity (January, 1999) RPM (June 2007)
- Financial Transmission Rights (June 1, 1999)
- Ancillary Services Markets
  - Regulation (June 1, 2000)
  - Synchronized Reserves (December 1, 2002)
  - Day-ahead Scheduling Reserves (June 2008)
  - Black Start Services (December 1, 2002)
  - Reactive Services

Cost Based Services
Market Transparency is Key to Efficient Operation
Locational Marginal Pricing

LMP = System Energy Price + Transmission Congestion Cost + Cost of Marginal Losses

3 Components of LMP

Hot Topic: consistency in the calculation of the congestion and loss components of the LMP

PJM Interconnection, L.L.C., 138 FERC ¶ 61,038 (2012)
ARRs and FTRs

Entire PJM System Capability

Annual Allocation
- ARRs allocated (MWs)

Annual FTR Auction
- FTRs awarded to bidders (MWs & price)

Hourly
- Congestion charges

Auction Revenue Rights

Auction Revenue

Hot Topic: insufficiency of congestion charges to fund outstanding FTRs.

- Complaint and Request for Fast Track Processing of the FirstEnergy Companies, Docket No. EL12-19-000 (December 28, 2011)
- FirstEnergy Solutions Corp., et al., 138 FERC ¶ 61,158 (2012)
- Complaint and Request for Fast Track Processing, Docket No. EL11-25-000 (March 2, 2011)
- PPL Energy Plus, LLC, 134 FERC ¶ 61,263 (2011)
Hot Topic: Performance based compensation in the Regulation market

The History of the Theory

• Who ever heard of Homeostatic Utility Control?
  – The original name of Electricity spot Pricing

• The original Cast of Characters
  – Fred C. Schweppe; MIT Professor of EE → Power Systems Control Theory
  – Michael C. Caramanis; Now BU Professor of Engineering → OR
  – Richard D. Tabors; MIT Research Engineer → Regional Economics
  – Roger E Bohn; Now Professor UC San Diego → Applied Economics

• Our original objective was to integrate the demand side with the supply side of the electric power sector

• 1989 published Spot Pricing of Electricity or “The Yellow Book”
The Objectives on Electricity Market Design

• Increased Efficiency
  – Short Run Dispatch
  – Long Run Investment
  – Integration of Demand
  – Integration of non-utility generation
  – Integration / rationalization of transmission
How Do You Price Electricity (and transmission)?

• If you believe microeconomic theory, short-term electricity should be priced (and valued) “at the margin”
• The marginal value of electricity is a function of TIME and SPACE on the grid
• VOCABULARY: Spot price, Nodal price, Real Time price (RTP) and Locational Marginal Price (LMP) are all terms frequently used for this concept
• The price (and value?) of energy (and transmission) is fundamentally linked to the spatial spot prices on the grid
  – The value of energy at any node will be the spot price at that node
  – The value of transmission between two nodes (at economic equilibrium) will not to exceed the difference in the spot prices between these nodes
The Elements of the Spot Price

• Marginal Cost / Value of energy
• Marginal Cost / Value of Losses
• Marginal Impact of Transmission Constraints
• Marginal Value of Scarcity (Customer’s Willingness to Pay)
  – This got lost in the regulatory morass of California (and elsewhere) price spikes
  – Necessitates the Chewing Gum and Bailing Wire efforts of creating Capacity markets to fill in for the “missing money” of the market
Calculation of Locational Marginal Prices: Examples

- The following examples show how nodal prices can be calculated from the system dispatch and why prices can vary locationally
  - System dispatch with and without congestion
  - Calculation of nodal prices

For simplicity, all examples are shown without losses
One-Node Example

Node: A single point in the transmission system where one or more generators or loads are connected by zero-impedance lines with no internal transmission limits

Here, a generator and load are located at node A

Capacity: 50 MW
Offer = $30/MWh
Load: 40 MW
Dispatch = ?
Price = ?
One-Node Example

Capacity: 50 MW
Offer = $30/MWh

Load: 40 MW

Dispatch = 40 MW
Price = $30/MWh

Simple enough?
Two-Node Example

Capacity: 50 MW
Offer = $30/MWh
Dispatch = ?
Price = ?
Load: 40 MW

Capacity = 30MW
Offer = $20/MWh
Dispatch = ?
Price = ?
Two-Node Example

Capacity: 50 MW
Offer = $30/MWh

Dispatch = 10 MW
Price = $30/MWh

Load: 40 MW

Capacity = 30MW
Offer = $20/MWh

Dispatch = 30 MW
Price = $30/MWh
Two-Node – Example with Congestion

Capacity: 50 MW  
Offer = $30/MWh

Dispatch = ?  
Price = ?

Load: 40 MW

Capacity = 30MW  
Offer = $20/MWh

Dispatch = ?  
Price = ?

Constraint: 20 MW
Two-Node – Example with Congestion

When unconstrained optimal flow exceeds the capacity of the line with the constraint, the markets separate and the nodes are priced differently. Still simple enough, yes?
In this example we assume that the transmission lines are all of equal impedance (Z), there are no transmission constraints and losses are zero.

*How does the power flow?*
Three-Node Example

*Power flow is inversely proportional to impedance (or – in other words – resistance of flow)*

- Power flow from G1: $\frac{2}{3}$ to L, $\frac{1}{3}$ to G2 to L

Power flow from G2: $\frac{2}{3}$ to L, $\frac{1}{3}$ to G1 to L
Three-Node Example

What system dispatch serves L at the lowest price?

*First dispatch the least expensive resource, G2*

G2 at full load serves 30 MW of L, but notice the 1/3, 2/3 split of flow to serve L.
Three-Node Example

_G1 is then dispatched to meet load_

<table>
<thead>
<tr>
<th>G1</th>
<th>G2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bid = $30/MWh</td>
<td>Bid = $20/MWh</td>
</tr>
<tr>
<td>Capacity = 50 MW</td>
<td>Capacity = 30 MW</td>
</tr>
<tr>
<td>Dispatch = ?</td>
<td>Dispatch = 30 MW</td>
</tr>
</tbody>
</table>

Load = 50 MW

An additional 20 MW from G1 is need to meet the 50 MW of load at L
The 20 MW of output from G1 also follows the 1/3, 2/3 split

- **G1**
  - Bid = $30/MWh
  - Capacity = 50 MW
  - Dispatch = 20 MW
  - 13.3 MW to L
  - 10 MW to G2

- **G2**
  - Bid = $20/MWh
  - Capacity = 30 MW
  - Dispatch = 30 MW
  - 20 MW to L
  - 6.7 MW to G1

- **L**
  - Load = 50 MW

G1

G2

Load = 50 MW
Three-Node Example

Resulting total flows are as summarized

<table>
<thead>
<tr>
<th>From G1</th>
<th>From G2</th>
<th>Net Line Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>To L</td>
<td>To G2 to L</td>
</tr>
<tr>
<td>20.0</td>
<td>13.3</td>
<td>6.7</td>
</tr>
</tbody>
</table>

What are the LMPs at each node?
To determine the LMP at L: first determine how L can be served at least cost

Bid = $30/MWh
Capacity = 50 MW
Dispatch = 20 MW

Bid = $20/MWh
Capacity = 30 MW
Dispatch = 30 MW

Next determine the cost of serving L with that dispatch

The LMP at L is defined as the marginal cost of the next increment (e.g. MW) consumed at L

With no constraints, the 51st MW supplied will be from G1 at $30/MWh
What if a transmission line is constrained at a 20 MW limit?

Bid = $30/MWh  
Capacity = 50 MW

Bid = $20/MWh  
Capacity = 30 MW

50 MW must still be delivered to L. How can this be done?

Since G2 has twice the impact on the constrained line as G1, it is intuitive that the resulting solution is one that backs down G2 and increments G1.

The increase in cost of generation is the congestion cost for the system.
Constrained Example

The dispatch solution is the solved set of equations that minimizes cost without exceeding the constraint limit.

Through experimentation, let’s back down G2 by 1 MW and increase G1 by 1 MW.

Bid = $30/MWh
Capacity = 50 MW

Bid = $20/MWh
Capacity = 30 MW

Load = 50 MW
Price should be “higher”

Unconstrained flow = 26.7
Modified flow = 26.3

It helps a little, but further shifts from G2 to G1 are necessary to reduce flow on the constrained line to \( \leq 20 \text{ MW} \).
Constrained Example

Note that the production at G2 decreases from 30 MW to 10 MW due to the constraint. This 20 MW decrease is offset by increasing production at G1, which is the more expensive node. Now what is the LMP at L?
Let’s examine the LMP at L in more detail

As we discovered, an incremental MW served at L would have to come from G1

Therefore is the LMP at L = the marginal bid price of G1?
By definition, the LMP at L is determined as follows:

The marginal cost of the next unit consumed at L will be the LMP.

With the constraint, the only way to obtain the 51st MW is to back down the production at G2.

Then production is increased at G1 by 2 MW (1 MW to replace the lost production at G2 and 1 MW to provide the marginal MW at L).

This redispatch prevents the constraint from being violated. i.e. 1 MW backed down from G2 relieves the constraint by 2/3 MW, and a 2 MW increase at G1 increases the flow back to level of constraint (1/3 * 2 MW)
Constrained Example

Bid = $30/MWh
Capacity = 50 MW
Dispatch = 40 MW

Bid = $20/MWh
Capacity = 30 MW
Dispatch = 10 MW

Load = 50 MW

LMP = $40/MWh

Thus, the marginal cost of the next unit consumed at L = LMP:

$\text{LMP} = (-1 \text{ MWh at G2} \times $20/\text{MWh}) + (2 \text{ MWh at G1} \times $30/\text{MWh})$

$\text{LMP} = -$20 + $60$

$\text{LMP} =$40/\text{MWh}$

Note that the LMP at L is NOT EQUAL TO the marginal cost of G1 or G2.
It is greater than both the prices G1 and G2!
Locational Marginal Pricing

LMP: Value of an increase/decrease of a MW of load at a specific location, considering generation marginal cost (including opportunity cost), transmission congestion, and losses.

LMP provides the “correct” signal to generate and consume in a manner that reduces the cost of redispatch around transmission constraints.

LMP requires economic market inputs (supply/demand bids) and physical system inputs (power flow data), and simultaneous calculation at all locations on the grid by a centralized system and market operator.
Energy Bar Association

RTO/ISO Energy Markets
A Regulatory Attorney’s Perspective

Sean Atkins
April 25, 2012
Legal Standard

- Public utilities, including ISOs/RTOs, must file for FERC approval the rates, terms, and conditions for transmission services and wholesale electricity sales. *Federal Power Act §§ 201, 205, 206 (16 USC §§ 824, 824d, 824e).*
- Rates, terms, and conditions for wholesale energy/ancillary service markets and related transmission pricing rules must be “just and reasonable” and “not unduly discriminatory or preferential.”
- In arriving at a just and reasonable rate, “no single method need be followed.” *See Wisconsin v. FPC, 373 U.S. 294 (1963).*
California Originally Had a Very Different Market Design

- Zonal congestion management – no pricing of congestion within zones
- The California ISO administered day-ahead ancillary service markets, but only real-time imbalance energy markets
- The PX administered a day-ahead energy market, which ceased operations in 2001
LMP Comes to California

- Day-ahead Integrated Forward Market that optimizes procurement of energy and ancillary services, manages transmission congestion, and satisfies reliability requirements
- System and Local Market Power Mitigation
- Locational Marginal Pricing – nodal prices reflect congestion and marginal transmission losses
- Congestion Revenue Rights – financial rights to allow parties to hedge congestion cost risk
- Real-time market processes result in final unit commitment and economic dispatch using the same approach to optimization used in day-ahead market
California ISO
Market Design Features

• Hour-Ahead Scheduling Process as part of the real-time market processes – allows for changes to intertie schedules without creating a full hour-ahead settlement market

• Long-term capacity needs addressed by a Resource Adequacy program administered by CPUC and local regulatory authorities, supplemented by ISO backstop procurement authority

• The ISO uses Residual Unit Commitment to secure incremental capacity that will be needed in real-time to meet the demand forecast but may not have been committed in the Integrated Forward Market
Drivers of Market Design Changes

• Regulatory mandates
  – Direct (e.g., FERC’s Frequency Regulation Compensation rule, 137 FERC ¶ 61,064)
  – Indirect (e.g., California 33% RPS requirements, once-through cooling)

• Changes in technologies and resource mix (e.g., smart grid, demand response)

• Market enhancements

• Fix identified market flaws
Hot Topic: Renewable Integration

Numerous market design enhancements being developed or under consideration by the California ISO, including:

- Lowering energy bid floor to incent additional decremental bids
- Pay for Performance Regulation (complies with FERC’s Frequency Regulation Compensation rule)
- Flexible ramping products
- Hourly intertie pricing & settlements
- Forward procurement of flexible capacity
Considerations Informing Market Enhancements

• **Software**
  – Major market software changes must be designed, tested, and implemented in releases often scheduled years in advance
  – Design features from other LMP markets generally are not “plug and play”

• **Stakeholder Process**
  – Significant market design enhancements undergo an extensive stakeholder process
  – RTOs/ISOs are expected to address significant stakeholder concerns when making FERC filings; others are expected to raise significant issues in the stakeholder process
RTO Energy Markets: Theory, Design and Challenges

Presented to the Energy Bar Association by:

David B. Patton, Ph.D.
President, Potomac Economics

April 25, 2012
Why Do Markets for Electricity Make Sense?

- Electricity has unyielding physical properties:
  - Electricity production (supply) must always and continuously equal customers’ consumption (demand).
  - Flows over the transmission network are determined by physical properties.
    - It must be produced at a set of locations that will not overload any line in the transmission network.
    - It is often consumed at different locations from where it is produced.
  - Must also account for physical restrictions of generators and other resources.
- Accommodating these physical properties and demands requires a high degree of coordination.
- Achieving this coordination through electricity markets should result in:
  - Lower overall costs;
  - More accurate price signals to guide investment; and
  - Improved reliability.
What Do System Operators Do?

- System operators must “keep the lights on”, requiring them to:
  - Balance supply and demand, i.e. keep frequency at a constant 60Hz;
  - Monitor and maintain voltage throughout the network;
  - Coordinate the commitment of resources (turning resources on and off);
  - Send “dispatch” signals to resources (how much energy to produce);
  - Monitor/control network flows to manage congestion;
  - Manage operating reserves; and
  - Monitor contingencies and respond to system emergencies.

- **Fundamental Principle**: Markets should coordinate and satisfy the reliability needs of the system to the maximum extent possible because:
  - Participants will have the incentive to do what the operator needs them to do;
  - The markets will provide accurate signals to guide longer-term decisions; and
  - Operator intervention generally distorts market outcomes—these effects are generally larger than the actions of any single participant.
Market Functions and Operator Actions

- Operator Actions
- Market/Econ. Dispatch
- Both

- Commitments for Reserves
- Manage Reserves
- Schedule Inter-area Transactions
- System Operator Actions
- Day-Ahead/Real-Time Market: Economic Dispatch
- Automated Regulation
- Monitor Flows and Contingencies
- Commitments to Manage Flows
- Maintain Voltage and Frequency
- Congestion Redispatch

TLR
Real-Time Markets

- The five-minute real-time dispatch ensures that real-time network demands are met optimally with the lowest-cost resources.
- Well-designed real-time markets jointly satisfy energy, operating reserves and regulation (“ancillary service”) requirements.
  - Regulating reserves automatically maintain system frequency at 60 Hz.
  - Operating reserves provide additional capacity to meet unanticipated increases in demand or disruptions to supply.
- The real-time market optimally allocates resources between these products on a five-minute basis.
- Participants may schedule physical imports and exports on an hourly basis in some markets, and on a 15-minute basis in others.
  - Efficient scheduling is difficult to achieve because schedules must generally be submitted 30 to 90 minutes in advance of when they will flow.
- Some real-time markets economically commit and de-commit peaking resources. In other markets, operators do this manually.
In addition to meeting the physical needs of the system, an essential function of the real-time market is to provide efficient prices because these prices:

- Provide incentives for participants to follow operator instructions;
- Motivate participants to buy and sell efficiently in the day-ahead market;
- Facilitate efficient longer-term forward contracting; and
- Provide price signals to govern generation and transmission investment.

For energy, the real-time market sets locational marginal prices ("LMP") at the marginal cost of electricity at every location, which reflects:

- The economic value of transmission constraints (that limit the dispatch of lower-cost resources); and
- The marginal value of transmission losses.

For ancillary services, the costs of the trade-offs between energy and these products are included in both the ancillary service and energy prices.

- Efficient shortage pricing is ensured because the economic value of reserves and regulation (as set by "demand curves") are included in all prices when the real-time market is short of a product.
Day-Ahead Markets

- While the real-time market is physical, the day-ahead market is largely financial.
- The day-ahead market establishes hourly, financially-binding, one-day forward contracts for energy and ancillary services.
  - The vast majority of settlements occur through the day-ahead market, including the purchase/sale of energy and reserves, and collection of congestion revenue.
  - The real-time market only settles “deviations” from the day-ahead market (usually only 1 to 2 percent of all settlements).
- The day-ahead market is important because it coordinates the least-cost commitment of resources to satisfy expected real-time demands.
  - The day-ahead market’s benefits are contingent on its outcomes converging well with those in the real-time market. In general, this depends on:
    - Consistent topology and assumptions between the two markets; and
    - Price-sensitive bids and offers, including active virtual trading (day-ahead purchases and sales that are settled back at real-time prices).
  - Although virtual trading must be monitored, it is an essential component of the day-ahead market providing most of the true liquidity.
What is Market Power and When is it a Problem?

- Market power is the ability of a firm to profitably raise prices.
- Market power exists in nearly every product market, most of which are not regulated. Only perfectly competitive markets exhibit no market power.
  - In general, the cost of eliminating all market power is far greater than the benefits of doing so. Hence, "workably competitive" is the objective.
- Market power in electric markets is usually caused by local needs or network constraints that isolate areas with few (or sometimes one) competitors.
  - Since these conditions are generally transitory, "behavioral" mitigation to limit abuses of market power during a small number of hours is appropriate.
  - This allows markets to operate unfettered in all other hours.
- Every market in the U.S. has some form of real-time mitigation to address locational market power.
  - Behavioral mitigation should not affect participants that are behaving competitively.
Challenges: Where the Real World Meets Theory

• Allowing inflexible resources to set energy prices in a five-minute market:
  ✓ Peaking generating resources (e.g., gas turbines);
  ✓ Demand response resources; and
  ✓ Emergency actions taken by the operator.
  ✓ If these high-cost actions/resources don’t set the real-time energy prices when they are needed to satisfy the system’s needs:
    – Day-ahead scheduling and commitments will be inefficient; and
    – Longer-term economic signals will be distorted.

• Allowing the real-time market to anticipate changing demands beyond 5-10 minutes in the future and provide optimal dispatch instructions.

• Efficiently facilitating trading between markets.

• Accounting for and managing “loop flows” across the network created by others (or that the native market creates on others’ systems).

• Setting locational prices efficiently when constraints are violated.

• Allocating “uplift” costs efficiently.
David B. Patton, Ph.D.  
President, Potomac Economics  

David B. Patton is President of Potomac Economics and has 20 years of experience as an energy economist. He provides expert advice, analysis and testimony to clients in the electricity and natural gas industries. His areas of expertise include market design and monitoring, merger and other market power analysis, transmission pricing, asset valuation, and congestion management.

Potomac Economics currently serves as the Independent Market Monitor for the New York ISO, ISO New England, Midwest ISO and ERCOT. In these capacities, Dr. Patton advises the ISOs on market issues and monitors the markets to identify and remedy flaws in the market design or attempts to exercise market power. Potomac Economics has also provided independent monitoring of transmission operations or supply procurements for APS, PNM, PacifiCorp, OG&E, MidAmerican Energy, Duke, and Entergy.

Dr. Patton has provided expert testimony and analysis on competitive issues in a number of electric utility mergers, other antitrust cases, and market-based pricing cases before the FERC, state regulatory agencies, the Department of Justice and the Federal Trade Commission. Prior to consulting, Dr. Patton was a senior economist in the Office of Economic Policy at the FERC where he advised the Commission on policy issues ranging from transmission pricing and open access to mergers and market power.

Dr. Patton has published and spoken on a broad array of topics related to deregulation and the development of competitive electricity markets. He holds a Ph.D. in Economics from George Mason University, with concentrations in industrial organization and finance.
Demand Response
The Current State of U.S. Demand Response

Ryan Hledik

Energy Bar Association RTO/ISO Seminar
Washington, DC

April 25, 2012
The national landscape of demand response (DR)

Peak Demand Reduction Capability (as Reported to FERC)

This amounts to 53 GW of peak reduction capability (6% of U.S. peak)

Source: Derived from reported DR capability in 2010 FERC Assessment of Demand Response & Advanced Metering and state system peak projections in 2009 FERC National Assessment of Demand Response Potential

Note: For further discussion, see Kelly Smith and Ryan Hledik, “DR Drivers,” Public Utilities Fortnightly, January 2012
In 2009, Brattle identified 188 GW of DR potential

U.S. Peak Demand Projections

Source: 2009 FERC National Assessment of Demand Response Potential
FERC data suggests that we will get closer to our DR potential over the next five years.

Historical and Projected U.S. Demand Response

- **2006 - 2010**
  - Historical Growth = 79%

- **2010 - 2015**
  - Projected Growth = 56%

83 GW by 2015

Source: Adapted from 2010 FERC Assessment of Demand Response & Advanced Metering
Some challenges must still be overcome to achieve the potential

♦ Lack of strong financial incentives for utilities

♦ Short-term capacity surplus is limiting DR value in some markets

♦ Regulatory concerns over customer backlash

♦ Market design limitations

♦ Constraints on third-party participation
New developments could redefine the landscape

Policy initiatives
- State policy requiring dynamic pricing
- Demand-side prioritization in state policy
- FERC policy to promote energy market integration
- Federal funding for smart grid projects

Wholesale markets
- Changing supply-demand balance in capacity markets
- Renewables integration needs
- Increased role of aggregators

Retail markets
- Recession = greater electricity cost awareness
- Expansion of “green” segment of customers (e.g., EV adoption)
- “IT revolution” making tech available at lower cost
New developments could redefine the landscape

Policy initiatives
- State policy requiring dynamic pricing
- Demand-side prioritization in state policy
- **FERC policy to promote energy market integration**
- Federal funding for smart grid projects

Wholesale markets
- Short-term capacity surplus
- Renewables integration needs
- Increased role of aggregators

Retail markets
- Recession = greater electricity cost awareness
- Expansion of “green” segment of customers
- “IT revolution” making tech available at lower cost
Suggested reading


Ryan Hledik is a senior associate of The Brattle Group with expertise in assessing the economics of smart grid investments and policies. He has consulted to utilities, policymakers, technology firms, government labs, research organizations, and wholesale market operators. His contributions have included the development of widely cited models for the economic valuation of smart grid programs, serving as a member of a U.S. Department of Energy advisory group to review the activities of Smart Grid Investment Grant recipients, and providing strategic advice to firms implementing new smart grid initiatives.

Additionally, Mr. Hledik has been the lead developer of several energy market simulation tools for the purposes of wholesale price forecasting, asset valuation, and environmental impact analysis. A frequent presenter on the economics of the smart grid, he has recently spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, where his concentration was in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining The Brattle Group, Mr. Hledik was a research assistant with Stanford University's Energy Modeling Forum and a research analyst at Charles River Associates.
About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world. We combine in-depth industry experience, rigorous analyses, and principled techniques to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Climate Change Policy and Planning
Cost of Capital
Demand Forecasting and Weather Normalization
Demand Response and Energy Efficiency
Electricity Market Modeling
Energy Asset Valuation
Energy Contract Litigation
Environmental Compliance
Fuel and Power Procurement
Incentive Regulation
Rate Design, Cost Allocation, and Rate Structure
Regulatory Strategy and Litigation Support
Renewables
Resource Planning
Retail Access and Restructuring
Risk Management
Market-Based Rates
Market Design and Competitive Analysis
Mergers and Acquisitions
Transmission

Contact Ryan Hledik at ryan.hledik@brattle.com
353 Sacramento Street, Suite 1140
San Francisco, CA 94111
Appendix:
The emerging DR landscape
The current DR program portfolio is fairly diverse

- 53 GW of peak reduction
- ~6% of U.S. peak
- Only 20% residential
- The rest is split between commercial, industrial, and wholesale

U.S. DR Programs (Share of MW)

- Time-Varying Rates 8%
- Other 3%
- Other Incentive-Based 26%
- Emergency Demand Response 25%
- Direct Load Control 17%
- Interruptible Load 21%

Comments

Source: Adapted from 2010 FERC Assessment of Demand Response & Advanced Metering

Energy Bar Association RTO/ISO Seminar
April 25, 2012
Recent DR research has focused largely on residential dynamic pricing.

18 Recent Residential Pricing Pilots

Note: Map excludes full-scale rollouts such TOU rates at APS and SRP

International pilots include Australia and Canada
More than 100 combinations of rates and technologies have been tested
The pilots show that the strength of the price signal influences customer responsiveness.
Responsiveness increases at a decreasing rate

Pilot Impact vs. Price Ratio (No Enabling Tech)
Results are mostly within a range explained by central air-conditioning saturation

Pilot Impact vs. Price Ratio (No Enabling Tech)
However, while much of the potential is in dynamic pricing…

U.S. Peak Demand Reduction Potential by 2019

- Other DR
- Interruptible Tariffs
- DLC
- Pricing w/o Tech
- Pricing w/Tech

Dynamic pricing contribution

Source: 2009 FERC National Assessment of Demand Response Potential
…plans for new DR programs are only partly consistent with the potential estimate

The share of dynamic pricing in planned new programs will increase in the next five years

However, non-pricing programs will still represent majority of new DR through 2015

Source: Adapted from 2010 FERC Assessment of Demand Response & Advanced Metering
New concepts will be tested in DOE-funded consumer behavior studies

- Variable peak pricing
- PTR as a transition tool
- Technology acceptance
- Pre-payment billing
- Sample selection methods
- Pricing period duration
- Bill protection
- Information access patterns
- Enhanced education
- Test-and-learn

Other funded pilots are still under review
DR could add value in new ways in the future

Renewables integration
- Requires frequent interruption and investment in automation technologies – will customers participate?
- A study on potential value of DR in integration would help to quantify the magnitude of this opportunity

Plug-in electric vehicles
- Distribution-level reliability is a near-term challenge with clustered adoption
- The effectiveness of TOU rates will depend on the price elasticity of charging
- Some form of charging control will be critical at high adoption rates

Permanent load shifting
- How do the economics change with significant addition of renewables?
- Are retail price signals sufficient to encourage adoption where economic?

Creating shareholder value
- In an environment of rising retail rates, regulators are likely to become increasingly cost-conscious
- Can the cost-saving nature of DR improve the utility’s bottom line?
“FERC’s Order on Demand Response Compensation: An Assessment”
Nancy E. Bagot
Vice President, Regulatory Affairs
Electric Power Supply Association
Wednesday, April 25, 2012
Demand Response Compensation (FERC Order No. 745)

(1) Order 745 raises economic, operational and legal concerns

(2) Implementation by RTOs

(3) So what is DR anyway?
Demand Response

- EPSA supports DR as a competitive market participant
- Participation must be economically rational, market-based
- Wholesale market rules under the Federal Power Act must be Just & Reasonable for jurisdictional market participants

The Order

- Initiating premise: 1 MW of demand equals 1 MW of generation
- Applied uniformly across all RTOs
- Full Locational Marginal Price (LMP) without an offset for the foregone purchase
“While the merits of various methods for compensating demand response were discussed at length in the course of this rulemaking, nowhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets. On this point, there is no debate. The fact is that demand response plays a very important role in these markets by providing significant economic, reliability, and other market-related benefits.”

Commissioner Philip D. Moeller’s Dissent
Order No. 745, Docket No. RM10-17-000
March 15, 201
Commissioner Moeller Got It Right Again

“However, in a misguided attempt to encourage greater demand response participation in the organized energy markets, today’s Rule imposes a standardized and preferential compensation scheme that conflicts both with the Commission’s efforts to promote competitive markets and with its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates. For these reasons, I cannot support this Rule.” [citation omitted]

Commissioner Philip D. Moeller’s Dissent
Order No. 745, Docket No. RM10-17-000
March 15, 2011
Critical Economic and Operational Flaws

- LMP compensation must reflect the cost of the foregone purchase
- Full LMP is a subsidy to foster a desired resource
- Net Benefits Screen indicates flawed economics of the subsidy, impact to certain customer classes
- Basis for generator market power mitigation not supported by analysis or conforming changes to current mitigation schemes
- No analysis that wholesale prices need to be (artificially) suppressed
- Equivalent or comparable? DR described throughout rule as a balancing service
- To be comparable, DR must be fully dispatchable and operate pursuant to the same applicable market rules, obligations and requirements (both FERC and NERC)
Critical Legal Flaws

- Order designed to resolve retail barriers (lack of dynamic retail pricing) by mandating wholesale compensation
- DR is a retail “non-sale”
- Federal Power Act Just & Reasonable compensation obligation to jurisdictional wholesale market participants (on grid generators)
- While perhaps not limited to “textbook economics,” FERC is limited to wholesale economics
- Lack of adherence to Administrative Procedures Act by ignoring the weight of the record, numerous concerns raised by parties at all stages of rulemaking proceeding
Implementation: The Rubber Hits the Road

- Majority of concerns lie with Order overall
- DR Providers and Industrials objections to:
  - Dispatch and self-scheduling requirements, changes
  - Baseline calculation revisions
  - Measurement & Verification modifications
- Behind the Meter Generation (“BTM” of “Off Grid”) emerges at this phase regarding its role, use as DR and operational considerations
Behind the Meter Generation

- Not addressed in Order No. 745
- MISO explained BTM not a genuine load reduction, therefore not accepted as full LMP DR product in energy market
- No available information or apparent analysis on extent of BTM (FERC or RTOs)
- As an actual generation product, BTM raises concern over impacts on market power analysis, mitigation, rules & obligations that apply to “on grid” generation
- Do “virtual power plants” quash incentives for generation needed for reliability, ancillary service capabilities?
Today: What is DR Anyway?

- Additional contexts raise this question anew
- “Variable identities” based on venue
  - **FERC**: 1 MW = 1 MW warranting full LMP
  - **EPA**: *RICE NESHAP* (Reciprocating Internal Combustion Engines) – as a “last line of defense against brownouts or blackouts” (EnerNOC) RICE require waiver of restrictions on run times
  - **NERC**: Proposal recommends it is not necessary to register in NERC’s Functional Model as “it is not an active facility or component like a generator” and there are “little or no reliability impacts” if DR does not perform
Conclusion

Briefing at the US Court of Appeals DC Circuit begins June 6 (consolidated under Case 11-1486)

Implementation moves forward: PJM went live April 1, others staggered over several months, possibly years
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PJM Interconnection, L.L.C.  )  Docket No. ER11-4106-000
California Independent System Operator Corporation  )  Docket No. ER11-4100-000
New York Independent System Operator, Inc.  )  Docket No. ER11-4338-000
ISO New England, Inc.  )  Docket Nos. ER11-4336-000
ISO New England, Inc.  )  ER11-4336-001
ISO New England, Inc.  )  ER11-4336-002
Midwest Independent Transmission System Operator, Inc.  )  Docket No. ER11-4337-000
Southwest Power Pool, Inc.  )  Docket No. ER11-4105-000
Demand Response Compensation In Organized Wholesale Energy Markets  )  Docket No. RM10-17-000 (Not Consolidated)

COMMENTS, MOTION FOR LEAVE TO ANSWER AND ANSWER OF THE ELECTRIC POWER SUPPLY ASSOCIATION ON ORDER NO. 745 COMPLIANCE FILINGS

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),\(^1\) and the Commission’s August 31, 2011 “Notice of Extension of Time” issued in Docket No. ER11-4337-000, the Electric Power Supply Association (“EPSA”)\(^2\) hereby submits these comments and this motion for leave to answer and answer in the

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\(^2\) EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which collectively account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.
above-captioned proceedings, which address the filings submitted by each
independent system operator and regional transmission organization
(“ISO/RTO”)\(^3\) in compliance with the Commission’s directives in Order No. 745.\(^4\)

EPSA has separately filed comments on the CAISO, ISO-NE, NYISO, and
PJM Compliance Filings to address issues particular to each compliance
proposal,\(^5\) and noted the intention to submit additional comments on any or all of
the compliance filings after all of the ISO/RTOs submitted their respective
implementation proposals. This step back and assessment of the compliance


\(^4\) See also Demand Response Compensation in Organized Wholesale Energy Markets, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,656 (2010) (the “NOPR”). As explained further below, in this filing, EPSA is submitting comments on the MISO Compliance Filing. In addition, EPSA moves, to the extent necessary, for leave to answer and answer the protests and comments filed in the other five Order No. 745 compliance proceedings, pursuant to Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011). Although the Commission’s procedural rules do not provide for answers to protests or comments as a matter of right, the Commission regularly allows answers where, as here, the answer provides further explanation or otherwise helps ensure a full and complete record and Commission understanding of that record. See, e.g., PJM Interconnection, L.L.C., 104 FERC ¶ 61,154 at P 14 (2003); Williams Energy Mktg. & Trading Co. v. Southern Co. Servs., Inc., 104 FERC ¶ 61,141 at P 10 (2003); Ameren Servs. Co., 100 FERC ¶ 61,135 at P 15 (2002).

filings as a whole is necessary in these proceedings due to the lack of specificity and detail in Order No. 745, as EPSA and others have pointed out throughout the rulemaking proceeding established in Docket No. RM10-17-000. Certain concerns or issues are specific to particular ISO/RTO regions, whereas others are shared by all of the organized markets. That has proven to be the case, and EPSA is therefore submitting this answer and comments to address the broad concerns that are common to each region and thus should be raised in each ISO/RTO compliance proceeding.

Of note, broad concerns in many cases have been highlighted in the ISO/RTO compliance filings themselves, but the bulk of these issues are raised in stakeholder comments and protests. For this reason, EPSA is submitting the instant filing to respond to these comments and protests. Largely, the compliance filings have sparked response and criticism from demand response ("DR") providers who interpret Order No. 745 to mandate greater compensation for DR resources, but ignore the fact that the pre-condition for such resources to be eligible for the higher, locational marginal price ("LMP") pricing is that the DR product or service must balance supply and demand in a manner comparable to generation. In their protests of the proposed changes to self-scheduling options, measurement and verification ("M&V") tools, baseline calculation and reliance on behind-the-meter generation ("BTM Generation"), DR providers have revealed an aversion to subject themselves to the same requirements as generators, while at the same time demanding that they receive greater compensation than generation. DR providers and industrial customer protests serve as exhibit A as
to why the Commission must revisit this Final Rule. These and other stakeholder comments pose critical questions for the implementation of Order No. 745, and argue for the Commission to hold all of the above-captioned ISO/RTO compliance proceedings in abeyance in order to first fully address the insufficiencies and issues raised on rehearing of the Final Rule before implementation is required by the ISOs/RTOs. Both the details and the very foundation of the Final Rule remain in question, as highlighted by the compliance proceedings and the numerous implementation issues raised therein.

I. BACKGROUND

EPSA is fully supportive of competitive markets that efficiently and reliably utilize all resources to serve consumers, including DR resources. In that context, EPSA has maintained throughout the Order No. 745 rulemaking proceeding that the NOPR did not adequately explain or support the sweeping change to DR compensation for any one ISO or RTO, much less the adoptions of a standard pricing element across all ISOs/RTOs. The Commission should have tailored DR compensation to address specific, identified market barriers if and to the extent they exist. Instead, Order No. 745 establishes a pricing regime that subsidizes one set of market participants with funds from others in order to address a problem – the purportedly inadequate level of DR participation – that the Commission failed to establish actually exists. EPSA and others pointed out that the Commission’s proposal would result in substantial inequalities that will harm the market and consumers, and that will produce rates that are demonstrably unjust and unreasonable, and unduly discriminatory.
EPSA has highlighted the numerous defects and insufficiencies of the Final Rule in its comments filed in the Order No. 745 rulemaking proceeding, outlining extensive legal, economic, technical and practical market implementation flaws in the NOPR and the Final Rule.\(^6\) In addition, EPSA, along with other groups representing competitive suppliers and public power groups, filed two detailed rehearing requests of Order No. 745 that are still pending. The first rehearing request – which was jointly filed by EPSA other industry sector trade associations, including the National Rural Electric Cooperative Association and the American Public Power Association – challenged the Commission’s assertion of ratemaking authority, which under the FPA is limited to \textit{wholesale sales}, over rates for \textit{retail non-purchases}.\(^7\) The second rehearing request, filed jointly with several other competitive power associations, outlines a host of additional legal flaws in the Final Rule, in particular, the lack of evidence supporting Order No. 745’s finding that a uniform, national rule for DR compensation is necessary to ensure that ISO/RTO rates are just and reasonable, and the fact that it mandates DR compensation that will cause rates received by jurisdictional sellers to be unjust, unreasonable, and unduly discriminatory.\(^8\) Additionally, twelve other requests for rehearing and/or clarification were filed in this proceeding, representing eighteen entities and virtually every type of industry stakeholder or

\footnotesize{
\(^8\) See Request for Rehearing of the Competitive Supplier Associations, Docket No. RM10-17-000 (filed Apr. 14, 2011).
}
market participant. Most rehearing requests question the foundation of the Final Rule itself.

EPSA will not repeat here all of the arguments that are included throughout the record in the underlying rulemaking docket. However, as discussed herein and exemplified by the concerns and questions raised by the ISO/RTO Order No. 745 compliance filings, it is of the utmost importance that the Commission act on rehearing before acting on these compliance filings. Beyond the overarching legal and technical flaws in the Final Rule, there are several requests for clarification or rehearing that speak to the ISO/RTO’s ability to comply with the rule. EPSA supports requests that the Commission act quickly on rehearing, and before further resources are expended on complying with a rule that may well change fundamentally upon full consideration of the multiple requests for rehearing submitted to the Commission.

II. COMMENTS

A. Opposition to Limitations On DR Self-Scheduling Vitiates The Comparability Upon Which LMP-Based Compensation Is Predicated.

The theoretical foundation of Order No. 745 is that when DR “has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test”9 (i.e., when DR is behaving in a manner comparable to supply), it warrants comparable compensation. In response to concerns expressed throughout this proceeding that DR is not a product

9 Order No. 745 at P 2.
sufficiently similar or comparable to generation supply, the Commission explained its finding that they are as follows:

Generation and load must be balanced by the RTOs and ISOs when clearing the day-ahead and real-time energy markets, and such balancing can be accomplished by changes in either supply or demand. The Commission finds that in the organized wholesale energy markets demand response can balance supply and demand as can generation.

Commenters that oppose this finding do not adequately recognize a distinctive and perhaps unique characteristic of the electric industry. The electric industry requires instantaneous balancing of supply and demand at all times to maintain reliability. *It is in this context that the Commission finds that demand response can balance supply and demand as can generation when dispatched, in the organized wholesale energy markets.*

Though EPSA and a plethora of others have questioned the ability of DR to provide a product or service that is sufficiently comparable to that provided by generators to warrant the same compensation (leaving aside for the moment that payment of the full LMP for DR is higher than the compensation generators receive and, in fact, represents a subsidized overpayment), it is incumbent on the ISOs/RTOs to develop rules, obligations and requirements that ensure the greatest comparability possible while operating the system efficiently and reliably; preferably these parameters would have been clearer and more directly outlined in Order No. 745.

For example, ISO New England Inc. (“ISO-NE”), the New York Independent System Operator, Inc. (“NYISO”), and PJM Interconnection, L.L.C. (“PJM”) have each proposed tariff provisions to clearly identify and establish bidding and dispatch rules and obligations for DR to be eligible for the higher, LMP-based

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10 *Id. at PP 55-56* (emphasis added).
compensation mandated by Order No. 745. However, these provisions, which intended to ensure that DR provides a comparable service, are heavily opposed by several DR providers, which highlights the lack of sufficient discussion or explanation of the DR product or service in Order No. 745 and related proceedings.\(^{11}\) In particular, an *ad hoc* coalition of DR providers and large industrial and commercial customers that refers to itself as the “Demand Response Supporters”\(^{12}\) protest the limitations proposed by PJM on the ability of DR providers to self-schedule DR. While the PJM DR Supporters accept that DR “should be compensated at full LMP if the response occurs when LMPs equal or exceed the monthly benefits threshold,”\(^{13}\) they gloss over the requirement that DR must also *balance* supply and demand. As noted by PJM:

> [A] mere reduction in load does not “reduce[ ] the need for dispatching additional generation” if, due to the lack of notification to the dispatcher, PJM has already dispatched the generation as the most cost-effective option available. To the contrary, an unexpected reduction in load creates an imbalance that PJM must schedule around in a way that can lead to increased balancing operating reserves charges that are socialized among, and increase costs to, remaining loads.\(^{14}\)

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\(^{11}\) See Comments and Limited Protest of Demand Response Supporters at 2, Docket No. ER11-4106-000 (filed Aug. 12, 2011) (“PJM DR Supporters Protest”) (“PJM creates an undue burden and unnecessary barrier to participation by imposing strict scheduling and dispatch requirements for demand response.”); See also Comments and Protest of Demand Response Supporters at 4, Docket No. ER11-4338-000 (filed Sept. 9, 2011); Comments and Limited Protest of NEPOOL Industrial Customer Coalition at 5, Docket No. ER11-4336-000 (filed Sept. 9, 2011).

\(^{12}\) The “Demand Response Supporters” that protested the PJM Compliance Filing include the following companies: Converge, Inc.; EnergyConnect by Johnson Controls, Inc.; EnerNOC, Inc.; the PJM Industrial Customer Coalition; Wal-Mart Stores, Inc.; American Forest & Paper Association; and Viridity Energy, Inc.(collectively, the “PJM DR Supporters”). EPSA supports DR as an important part of well functioning competitive wholesale markets, and therefore objects to any insinuation that those not included in this coalition, or raising questions related to comments filed by this particular coalition, do not support demand response.

\(^{13}\) PJM DR Supporters Protest at 6.

\(^{14}\) See Answer of PJM to Comments and Protests at 8, Docket No. ER11-4106-000 (filed Aug. 29, 2011).
Similarly, ISO-NE’s Director of Demand Response Strategy explains:

The balancing of supply and demand is achieved when each energy resource follows Dispatch Instructions based on the bids/offers submitted to the ISO and on a least-cost security-constrained dispatch and commitment algorithm administered by the ISO. Self-scheduling, by definition, occurs outside of ISO resource commitment and dispatch, and therefore does not contribute to the balancing of supply and demand. Rather, self-scheduling requires the ISO to readjust the dispatch of other resources to rebalance the system.\(^\text{15}\)

Therefore, self-scheduled DR does not, and cannot, satisfy the very narrow Order No. 745 requirement that DR resources must actually balance supply and demand to qualify for LMP-based compensation.

In opposing changes to self-scheduling options for DR eligible for LMP-based compensation, the PJM DR Supporters assert that flexibility “[u]nder current rules” that “has been in place for many years,”\(^\text{16}\) and argue that such flexibility must be retained unchanged by the RTO. This request exhibits a lack of appreciation or understanding for what Order No. 745 is ostensibly trying to achieve, namely, a new regime in that DR must provide a product or service that is comparable to generation in balancing supply and demand in order to be eligible for LMP-based compensation. This is a new and specific DR product that will require tailored requirements and obligations. While the PJM DR Supporters dismiss generators’ comments in the Order No. 745 rulemaking proceeding as a mere attempt to thwart competitors,\(^\text{17}\) their protests in these compliance

\(^{15}\) See ISO-NE Compliance Filing, Attachment 5, Testimony of Henry Y. Yoshimura at 41:29-42:5 (“Yoshimura Testimony”).

\(^{16}\) PJM DR Supporters Protest at 3-4.

\(^{17}\) See, e.g., Motion for Leave to Answer and Answer of the Demand Response Supporters at 6-8, Docket No. ER11-4106-000 (August 29, 2011) (“Such exclusionary tactics by suppliers should be rejected.”).
proceedings underscore the fact that they are the ones who are seeking preferential treatment by arguing that DR must receive higher compensation for providing a product that is ostensibly comparable to that provided by generation, without being willing to make any concomitant changes to ensure that DR is actually comparable. In sum, if they wish to continue operating under pre-Order No. 745 dispatch procedures, they should continue to receive pre-Order No. 745 compensation, including cost allocation.

The outcry over changes to DR self-scheduling is particularly loud in the ISO-NE compliance proceeding, in which numerous industrial customer coalitions filed protests, including the NEPOOL Industrial Customer Coalition, the Industrial Energy Consumers Group, the Industrial Energy Consumers Group, Industrial Energy Consumers of America ("IECA"), the "Joint Commenters," the "Joint Parties," and the Association of Businesses Advocating Tariff Equality (a coalition of industrial companies). For example, IECA claims that, "[u]nfortunately, several of the nation’s ISOs/RTOs have taken up the banner of opposing comprehensive integration of demand response into their energy markets on a basis fully equivalent to electric generation," and then goes on to invoke the Public Utility Regulatory Policies Act of 1978 ("PURPA") to

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20 See Motion to Intervene and Protest of the Industrial Energy Consumers of America at 3, ER11-4336-000 (filed Sept. 12, 2011) (“IECA Protest of ISO-NE Filing”) (emphasis added). Of note, the ISO-NE Compliance Filing explicitly states that, “The best overall approach to complying with Order No. 745 is to fully integrate demand resources into the day-ahead and real-time energy markets and system operations infrastructure.” Yoshimura Testimony at 8:6-8.
support the even and fair treatment of small, independent generation by the
ISOs/RTOs.21 The protest of the Joint Parties claims that the Commission’s
proposed solution is “an equally clear qualification for resource eligibility,”22 citing
the Order No. 745’s twofold requirement that DR balance supply and demand
and be cost effective, but the “equal” qualifications appear to end with those two
requirements. The Joint Parties choose to ignore the fact that generation is
subject to much higher requirements, while receiving less compensation.

Such a response from numerous DR providers underscores the lack of
sufficient detail, discussion or response to commenters from the Commission in
Order No. 745. For example, PJM DR Supporters state that, “nothing in Order
No. 745 addresses existing self-scheduling opportunities for demand response
and, certainly, nothing in Order No. 745 requires RTOs and ISOs to eliminate any
existing self-scheduling opportunities.”23 Similarly, Joint Commenters state that,
“nothing in Order No. 745 implies or mentions the need for ISOs and RTOs to
search for or justify additional distinctions among otherwise eligible
customers…unless such customers cannot satisfy the requirements of balancing
supply and demand within the confines of the net benefits test.”24 This simplistic
argument that the plain language of Order No. 745 represents the exhaustive list
of DR qualifications to participate as a supply resource defies logic, as if DR

22 See Protest of Industrial Energy Consumers Group, EnerNOC, Inc., Comverge, Inc.,
Industrial Energy Group, and Minnesota Large Industrial Group at 4, Docket No. ER11-4336-000
23 PJM DR Supporters Protest at 4.
24 See Joint Protest of ISO-NE Filing at 8.
somehow behaves outside the physics of the bulk power market grid with no regard for the efficient and reliable dispatch of the system. The ISOs/RTOs, however, correctly interpret Order No. 745 to require a DR resource to actually be capable of providing a balancing service that is comparable to that provided by generators in order to be eligible for LMP-based compensation. In other words, far from compensating only that amount of DR efficiently dispatched to balance supply and demand, PJM DR Supporters seek to tip the balance in favor of as much DR as possible. The Commission should heed the interpretation of the independent operators of wholesale energy markets over the interpretation put forward by many DR providers, who stand to receive substantial, windfall profits in the form of subsidized over-payments under an expansive reading of Order No. 745’s scheme.

Order No. 745 provides little detail as to how DR resources are required to function in the ISO/RTO markets, apart from the statement that they must have “the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test.”25 While the ISO/RTO compliance proceedings may not be the appropriate venues to litigate Order No. 745’s numerous deficiencies, it is inescapable that these proceedings highlight those deficiencies, as DR providers and industrial groups argue that the ISO/RTO compliance filings “exceed[] the scope of the Order and fail[] to comply with the

25 Order No. 745 at P 2.
plain language of Order No. 745. These entities would have DR function as a self-certified product, outside of the scope of the ISO/RTO supervision, but paid by the ISO/RTO as a market resource. EPSA reiterates the need for the Commission to address the many open issues pending on rehearing in this rulemaking proceeding to limit the resources expended (and likely wasted) on efforts to comply with the Final Rule in its current form and to offer greater guidance going forward in order to establish a robust, viable market for DR, which EPSA supports, while protecting reliability and economic viability of the existing wholesale energy markets in the ISOs/RTOs.

B. M&V Tools And Baseline Calculation Enhancements Are Critical To Implementation.

Commenters expressed extensive concerns and criticisms of the proposed enhancements and improvements to the ISOs/RTOs' M&V tools and baseline calculation methodologies. Many agree that implementation of Order No. 745 will likely result in greater participation by DR providers. There should be no question then that, at the initial implementation stage of this new regime, M&V tools and baseline calculations must be clear and effective. It does a disservice to DR, as well as to all the other market participants, to adopt minimal and/or ineffective M&V or baseline calculation tools, as they may lead to market distortions or other problems. Order No. 745 is clear that this is necessary:

The Commission agrees that as a general matter demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resource, and expect ISOs and

RTOs to continue their evaluation of their existing rules in light of this Final Rule and make appropriate filings with the Commission.27 Therefore, EPSA respectfully submits that it is incumbent upon the ISOs/RTOs to review and enhance their M&V tools and baseline calculation methodologies as necessary, and the Commission should make it clear that such improvements are necessary for compliance with Order No. 745. As was the case with the protests to limitations on DR self-scheduling discussed above, protesting DR providers and industrial customers refer to the Final Rule's lack of detail to oppose any changes to M&V tools or baseline calculations, and go so far as to claim that any proposed enhancements are veiled attempts to erect barriers against DR entry in organized markets.28 Again these arguments defy logic, as the clear intent of Order No. 745 is to establish a regime that provides comparable treatment among all resources that are capable of balancing supply and demand. DR providers and their customers seem to think that this comparability is all about compensation without regard to concomitant obligations. This cherry picking should be rejected, as it ignores the fact that there are relevant differences even among resources that are otherwise comparable. By its very nature, DR poses particular M&V and baseline issues. ISOs/RTOs will therefore need to develop new tools, which are specifically tailored to the capabilities and requirements of DR resources, for measuring and verifying DR participation in the energy market. In particular, DR participation cannot be measured as the net total “output” of a product, as is the case with

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27 Order No. 745 at P 66.
28 PJM DR Supporters Protest at 7-8.
generation, but rather it is a reduction from an amount normally consumed that varies from customer to customer and is based on an administrative formula estimating historical demand. Moreover, if the definition of DR in Order No. 745 is to have any intellectual or operational integrity, DR cannot be equated with any reduction in load that occurs (or is certified by DR providers to have occurred), but must instead be a verifiable reduction from expected use relative to an established and viable baseline.

In addition, the provision of DR service is, generally speaking, not the primary business of the entity providing the service, as is the case with generation. Resistance to such meaningful tools indicates that, rather than seeking to facilitate the participation of DR as a reliable resource that is treated comparably to generation, DR providers are seeking unduly preferential treatment and compensation. Moreover, they urge the Commission to use something as fundamental to the nation as electricity to experiment with an untested “virtual” supply product predicated on paper transactions and commitments that may or may not be met, in place of, and displacing, a physical network of power plants that actually deliver generation supply. To do so for the real-time energy market is to take a gamble on the nation’s economy, and flies in the face of widespread concerns that DR may not be able to balance supply and demand when it is most needed.²⁹

²⁹ See Motion for EnerNOC to Amend the Agreement for Capacity Resources between the Potomac Edison Company and EnerNOC Inc. at 7, Maryland Public Service Case No. 9149 (June 28, 2011) (“Upon being awarded the Agreement, EnerNOC set out to contract with end users to obtain all the requisite Capacity Resources under the Agreement. As of May 31, 2011 (the deadline for enrollment for the 2011-2012 Delivery Year), despite its best efforts, EnerNOC did not obtain the requisite Capacity Resources for the 2011-2012 Delivery Year.”).
C. BTM Generation Poses Serious Concerns As A DR Product Or Service And Should Not Participate As DR Pursuant To Order No. 745.

In the rulemaking proceeding, EPSA and number other commenters questioned whether BTM Generation could, or should, be permitted to participate as DR resource that is eligible for LMP-based compensation. The Commission has not responded to these concerns. As noted initially and explained in depth in the EPSA NOPR Comments, the use of such generation is not in fact a genuine load reduction. Consequently, payment of full LMP, in addition to the savings that a customer using BTM Generation receives by not paying for the foregone retail purchases (or that an LSE receives from avoided wholesale purchases) creates the economically perverse incentive for generation to move behind the meter when possible, even where it is less efficient. Moreover, this permits the customer or LSE to serve its load outside of the ISO/RTO energy market, while at the same time being paid LMP by the same ISO/RTO, as if it had actually reduced its load. The dangers and concerns of this incentive were discussed at length in the EPSA NOPR Comments and in the attached policy paper by Professor William W. Hogan.30

Whether BTM Generation can qualify as a DR resource or be utilized to provide DR service hinges on whether it can be considered a reduction in consumption. The Final Rule defines DR as follows:

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30 See generally EPSA Comments, Attachment 1, William W. Hogan, Implications for Consumers of the NOPR’s Proposal to Pay the LMP for all Demand Response.
[A] reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.\textsuperscript{31}

MISO interpreted the rule literally, stating in a footnote:

[Demand Response Resources] that [are] Behind the Meter Generation (“BTMG”) will not be paid the full LMP, in part, because BTMG is not a demand response reduction in energy, pursuant to Order No. 745, but rather is an incremental increase in Energy behind the meters. See, Order No. 745 fn 2.\textsuperscript{32}

This is a fair reading of the Final Rule, as BTM Generation is not a net reduction in consumption. However, some have argued that BTM Generation could represent DR on a wholesale level, based on the fact that Order No. 745 requires only that consumption from the wholesale electricity grid be decreased. Within the discussion of M&V tools, the Commission agrees with stakeholders that demand reductions that are not genuine may be violations of the Commission’s anti-manipulation rules.\textsuperscript{33} In this context, does BTM Generation equate to a genuine reduction in demand or not? The Commission should address this debate and clarify that BTM Generation cannot participate as DR, based on the host of questions and concerns raised throughout the rulemaking process and emerging again in the ISO-NE compliance proceeding in particular.

In that proceeding, the ISO-NE Internal Market Monitor (“ISO-NE IMM”) issued an opinion on May 26, 2011, finding that BTM Generation does not face barriers to participate in organized wholesale energy markets and thus is outside the scope of Order No. 745, concluding that “apparent demand reductions

\textsuperscript{31} Order No. 745 at P 2 n.2.
\textsuperscript{32} MISO Compliance Filing at 16.
\textsuperscript{33} Order No. 745 at P 95.
created by the operation of behind-the-meter generation should not be treated as demand response.”

The IMM explains its finding as follows:

Since the benefits of demand response upon which the Order relies require genuine demand reduction, the market rules and the market monitor must ensure that demand response payments are made only when the demand reduction is genuine…. One issue that has been raised in the Order 745 rulemaking process is whether load reduction achieved by behind-the-meter generation should be treated as actual demand reduction and therefore compensated under Order 745. The IMM believes that treating generation behind the meter the same as demand reduction is inconsistent with Order 745, because it enables participants to inflate their baselines, thereby increasing the likelihood of payment for non-genuine demand response, and it will decrease market competitiveness. Additionally, the rationale, upon which Order 745 is based, that there are barriers to demand participation in the wholesale market, does not apply to behind-the-meter generation. The IMM believes that unlike demand resources, generation resources do not have barriers to participate in the wholesale market, and therefore, it is appropriate to consider behind-the-meter generators outside of the scope for demand reduction payment. Otherwise, the Commission would have enumerated the barriers to behind-the-meter generation and explicitly stated that generators behind the meter must be compensated as demand resources. Instead, Order 745 is silent on the issue.

The ISO-NE IMM then goes on to describe the other problems created by permitting BTM Generation to qualify as DR, in particular, the creation of gaming opportunities. According to ISO-NE, customers can artificially increase their

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35 Id. at 2 (emphasis added).
36 Id. ("For example, behind-the-meter generation has been used by demand resources to artificially inflate customer baselines to obtain payments while not taking any action to reduce load. This is accomplished by turning off a distributed generator that normally operates when the baseline is being calculated and then turning the distributed generator back on and resuming normal operation of the distributed generator when demand reduction is being measured. The result is that the demand resource is paid for operating normally.").
DR payments by inflating their baselines, or by moving generation currently in front of the meter to behind the meter. 37 This phenomenon creates problems for payment to DR providers relying on BTM Generation, but also raises a far greater concern, which is the slow but eventual erosion of the ISO/RTO markets themselves. As the Commission has repeatedly emphasized, large, centrally dispatched markets offer the most efficient, reliable and competitive markets for electricity. 38 The LMP-based energy market design was premised on all resources supplying energy receiving the same energy price for delivery of that electricity (and charging LMP to those who consume the electrons). Paying LMP to loads for phantom reductions in consumption (and also avoiding the LMP charges that would have been incurred), and worse yet, paying BTM Generation the LMP while allowing it to also sell that energy to the behind-the-meter load, disrupts these efficiencies and produces unjust and unreasonable results. The Commission has long promoted the growth of organized markets, which are growing in both size and capabilities and are delivering substantial savings to ratepayers. Order No. 745 threatens to frustrate this long-standing Commission policy by creating economic incentives that would fracture these centrally organized markets into a patchwork quilt that destroys the economic efficiency and reliability assurance that they currently provide. As explained by the ISO-NE IMM:

37 Id. at 2-3.

It may appear that the behind-the-meter generation has met the Commission’s net benefits test and therefore increases market competitiveness. This is too narrow a view of competitiveness, because larger and more efficient generators have similar incentives to move behind the meter. If large generators begin to locate behind the meter of industrial and commercial customers, it would not only distort the wholesale price but makes it more difficult for the distribution and grid operators to protect contingencies caused by failures of behind-the-meter generators. Additionally, if behind-the-meter generation continues to receive this favorable treatment it will stifle investment in more efficient generation technologies in the wholesale market and raise prices to all customers over the long run, the opposite result from that which would occur in a competitive market. The impact of behind-the-meter generation on investment and system reliability warrants further study.  

At a minimum, EPSA agrees with the ISO-NE IMM that it is incumbent upon the Commission to openly address and analyze directly the impacts of BTM Generation on the organized markets, the viability of DR, and the treatment of wholesale generation on the grid in relation to BTM Generation.

Interestingly, in comments filed in the ISO-NE compliance proceeding, numerous industrial customer groups invoke PURPA to support the Commission’s treatment of DR. In one of the many industrial group filings in that proceeding, they state that:

One of the fundamentals of FERC energy policy is that small, independent generation as promoted by PURPA should be treated evenly and fairly by utilities. The fairness doctrine also applies to the operators of the nation’s regional transmission systems, without nondiscriminatory access to which, these smaller generators would be harmed, and without such generation, consumers would not be able to benefit.  

39 ISO-NE IMM Opinion at 3.
While this confusion and conflation between small, independent generation and demand response is perplexing, EPSA agrees with the premise of that argument – generators of all sizes should be treated equitably. Additionally, Order No. 745 notes:

The Commission agrees that as a general matter demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resource, and expect ISOs and RTOs to continue their evaluation of their existing rules in light of this Final Rule and make appropriate filings with the Commission.

The industrial customer groups’ constant references to the PURPA statute in their comments are both confusing and contradictory. The lesson of PURPA is actually on the side of those that, like EPSA, urge caution and careful examination of any federally-mandated compensation scheme for DR under the Final Rule as implemented through all of the compliance filings at issue in these proceedings. As a legal matter, it is not clear from the industrial group comments what specific provisions of PURPA are supposed to be relevant to the development and implementation of Order No. 745. The Final Rule makes no mention of PURPA whatsoever, much less does it cite to any provision of that statute as a legal basis for its issuance. Moreover, even as a rhetorical device or source of broad policy, the PURPA statute itself, and historical experience with its implementation, tends to refute, not support, the industrials’ arguments. First of all, while industrial commenters state that the regulatory scheme established by PURPA establishes fairness for all generators, it does not treat all generators equally. A number of principal provisions of PURPA (e.g., the requirement for

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42 Order No. 745 at P 66.
utilities to purchase the output of “qualifying facilities” (“QFs”) at higher, “avoided cost” rates, and the exemption of QFs from most provisions of the FPA) are available only to generators that are “qualifying small power production facilities”\(^\text{43}\) or “qualifying cogeneration facilities.”\(^\text{44}\) PURPA thus explicitly distinguishes among generators on the basis of size, fuel used, generation technology, ownership, date of certification of construction, or some mixture of foregoing factors.

In addition, commenters invoking PURPA ignore the fact that Congress amended the statute extensively in EPAct 2005 largely in response to claims that compensation under PURPA’s one-size-fits-all mandatory federal compensation formula had become exorbitant and excessive in certain cases. The relevant lesson of PURPA is that compensation formulas, even if well intended, can

\(^{43}\) Section 3(17) of the FPA, 16 U.S.C. § 796(17) (2006), defines the term “small power production facility,” and authorizes the Commission to promulgate further rules to determine whether a given facility is a “qualifying small power production facility.” 16 U.S.C. § 796(17)(C)(i) (2006). Specifically, the FPA defines a “small power production facility” as a facility that is an “eligible solar, wind, waste, or geothermal facility,” or a facility with a capacity of 80 MW or less that “produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof.” 16 U.S.C. § 796(17)(A) (2006). An “eligible solar, wind, waste, or geothermal facility” is one that uses solar or wind energy, or waste or geothermal resources, as the primary energy source and for which, either an application for QF certification or a notice of QF status was submitted to the Commission by December 31, 1994, or construction commenced by December 31, 1999. 16 U.S.C. § 796(17)(E) (2006). To be a qualifying “small power production facility,” the facility must be “owned by a person not primarily engaged in the generation or sale of power,” 16 U.S.C. § 796(17)(C)(ii) (2006), and it must satisfy the additional criteria and requirements set forth in the Commission’s regulations. See generally 18 C.F.R. Pt. 294, Subpt. B (2011).

\(^{44}\) “Small cogeneration facilities” are similarly defined through the interplay of the FPA’s statutory definitions and the Commission regulations. Section 3(18)(A) of the FPA, 16 U.S.C. § 796(18)(A) (2006), defines a “cogeneration facility” as a facility that produces “(i) electric energy, and (ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes.” Id. In addition, to be a “qualifying cogeneration facility,” the facility must be “owned by a person not primarily engaged in the generation or sale of power,” 16 U.S.C. § 796(18)(B)(ii) (2006), and it must satisfy additional requirements regarding minimum size, fuel use, and fuel efficiency that are set forth in the Commission’s regulations. See 16 U.S.C. § 796(18)(B)(i) (2006); 18 C.F.R. § 292.205 (2011) (setting forth operating and efficiency standards for “qualifying cogeneration facilities”).
produce undesirable results, which is the very point that EPSA and most other commenters have been making throughout the Order No. 745 rulemaking proceeding and in the instant compliance proceedings. In fact, as the Commission is well aware, subsequent to enactment of EPAct 2005’s amendments to PURPA, the Commission has moved as directed by those statutory amendments to remove the PURPA utility purchase obligation for many regions of the country served by organized markets based on EPAct 2005’s statutory test for competitiveness in regions and utility footprints. Thus, in the very same organized markets subject to the Final Rule’s compliance obligations, the Commission’s default assumption is that, by their very nature, ISO/RTO markets are sufficiently competitive to justify removal of the PURPA purchase obligation, and it has consistently granted the termination requests of utilities in such markets. Thus, the invocation of the spirit of PURPA past by industrial customers to justify yet another well intentioned but flawed federal compensation scheme, this time in the form of Order No. 745’s approach to DR, is simply not credible. In any case, there is no legal or factual basis for their claim that BTM


generation needs to be considered as DR in order to have fair access to competitive wholesale energy markets. The PURPA law as it exists today and the Commission’s application of it since EPAct 2005 compel a conclusion exactly the opposite of that urged by industrial customers. While PURPA may be relevant to the DR issue and the Order No. 745 compliance filings, its lesson is certainly not that urged by industrial customers.

Simply put, wholesale generation cannot be discriminated against in order to incent and support generation that is not part of the wholesale market. Preventing such unlawful discrimination is all that ISO-NE has attempted to do. ISO/RTO rules and requirements must apply equally to all generators, whether they are located in front of or behind the meter, that participate in the ISO/RTO market. The first step, then, is for ISOs/RTOs to determine (and to inform the Commission) how much BTM Generation exists in its footprint, how much is participating in its markets, how it is participating, how much DR is or could be BTM Generation, and whether the rules, obligations and requirements are being appropriately applied to BTM Generation as it is to other wholesale generation. Similarly, no one appears to know how much BTM Generation there is, what sort of fuel resource mix might be implicated, what environmental regulations might or might not apply or how it might participate in ISO/RTO markets. Quite simply, these are the facts that are missing from this discussion, and apparently not available, as EPSA’s inquiries to ISOs/RTOs, State commissions, and the Commission have not yielded any answers or quantifications. These are critical questions that must be answered without delay.
Many DR providers and industrial customers seem to want it both ways, namely, to keep their BTM Generation outside of and out of view from the ISOs/RTOs, but to be paid the full LMP by the ISO/RTO. The FPA requires the Commission to ensure that jurisdictional participants in the wholesale markets are treated fairly and equitably and that prices in those markets are just, reasonable, and not unduly preferential or discriminatory.

To do otherwise, as numerous DR providers and industrial companies and coalitions are urging, is not only unduly discriminatory to generators and other market participants, but threatens the reliability and efficiency of centrally organized regional electricity markets. Additionally, the participation of BTM Generation raises market power and mitigation concerns. If BTM Generation participation in the wholesale markets increases, that growth should be reflected in the market power analysis of “on grid” wholesale generation, which will have a correspondingly lower market share and therefore less market power. This reduction in generator market share and market power must be reflected in the application of market power mitigation mechanisms. Moreover, the price suppression due to DR in general, and to BTM Generation in particular, raises concerns as to whether compensation for wholesale generation will continue to be just and reasonable. As EPSA explained in the Joint Rehearing Request, generators have both a constitutional and a statutory right under the FPA to just and reasonable compensation, and it is the Commission’s obligation to ensure that they do, whereas there are no equivalent rights or responsibilities with
respect to the compensation received by non-jurisdictional BTM Generation or by DR resources more generally.

Again, these are serious and real concerns that need to be addressed before BTM Generation is permitted to participate (and to receive LMP-based compensation) in wholesale markets under the guise of DR. EPSA submits that BTM Generation should instead be required to participate as generation, rather than DR. This will be of particular concern if DR participation expands as predicted in light of increased compensation mandated by Order No. 745.48 As DR providers aggregate available BTM Generation MWs, large DR providers will represent blocks of generation (e.g., 300-500 MWs) that may well be equal or greater in size and market impact to traditional generation plants. That massive block of BTM Generation might participate as a DR resource under Order No. 745’s “comparability” theory as interpreted by some, but without being subject to comparable requirements, mitigation, or energy market settlement. The Commission and the regional market operators must ensure that there is no discrimination between BTM Generation and the on grid wholesale generation, just as there can be no discrimination between two on grid generators. This is a fundamental concern that goes to the heart of the debate over BTM Generation – is “off grid” supply really a DR resource and how should it be treated in the wholesale energy market settlement?

In its NOPR comments, EPSA highlighted the fact that “[n]othing in the NOPR’s proposed tariff language addresses this flaw and in fact the proposed

definition of ‘demand response’ would allow it.”

This oversight was not corrected in the Final Rule, and it leaves the ISOs/RTOs in a precarious situation in their attempts to craft compliance filings that are just and reasonable and do not distort their wholesale energy markets. Thus, in ISO-NE, an attempt to simply address (but still allow) BTM Generation has resulted in a debate that has reached a fever pitch, with unsubstantiated claims from industrial customers that large manufacturers might shut their doors based on the ISOs/RTOs’ treatment of DR. Notably, EPSA pointed to the impacts on jobs early in this proceeding, although EPSA’s concern was that overpayment for DR would result in load shifting or the shutting down of manufacturing in favor of more lucrative DR sales that employ far fewer people than if these entities actually fully engaged in their primary businesses. EPSA’s position appears to be supported by the claims of large industrials that they rely on DR payments to remain viable as businesses.

In another ironic twist, IECA claims, without substantiation or analysis, that ISO-NE’s proposal will harm the environment by promoting the utilization of peaking generation as opposed to efficient renewable generation or BTM Generation. EPSA similarly noted that Order No. 745 may negatively impact the environment, because it would promote the operation of less efficient, more polluting BTM Generation, which may not be subject to the same environmental

49 EPSA NOPR Comments at 26.
50 IECA Protest of ISO-NE Filing at 6 (“Reducing the economic viability of such large consumers by reducing their compensation for participation in DR and by exposure to unnecessarily high peak electricity or grid transmission charges, not only hurts their ability to provide direct jobs in their communities, but also creates secondary economic harm as vendors and suppliers are affected by the large consumer’s reduced economic activity.”).
51 Id.
laws or regulations as on grid generation, and would therefore discourage the development of new, cleaner and more efficient wholesale generation.\footnote{See EPSA NOPR Comments at 25-26, 57-62. EPSA notes that the Commission dismissed EPSA’s concerns. Order No. 745 at P 34.} This concern appears to have been borne out by efforts of DR providers to loosen regulations for the operation of BTM Generation under Environmental Protection Agency (“EPA”) regulations, including their successful efforts to persuade the agency to amend its National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (“RICE NESHAP”).\footnote{National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Docket No. EAP-HQ-OAR-2008-0708, 75 Fed. Reg. 9648 (Mar 3, 2010). (“RICE amendment”)} This amendment changed the operating limitations of existing stationary compression ignition reciprocating internal combustion engines (“RICE”) to permit these units to run for longer periods in order to participate in emergency DR programs.\footnote{See EPA, Notice of Proposed Rulemaking, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 75937 (Dec. 7, 2010). The proposed rule states that: “The petition from EnerNOC, et al. requested that EPA revise the allowance for emergency demand response operation in the final rule to allow the engines to be operated for a maximum of 60 hours per year or the minimum hours required by the Independent System Operator (ISO) tariff, whichever is less.”} In its own petition for reconsideration of this EPA action, the State of Delaware Department of Natural Resources & Environmental Control (“Delaware DNR&EC”) urges the agency to reconsider the amendment allowing RICE units to run as emergency DR, noting that in Delaware the RICE units represent a block of up to 127.5 MWs and that, in a three-hour period, they would emit between 315% - 530% more emissions than a new combustion turbine of similar...
size. The Delaware petition further points out that for these RICE units to run as DR, “such operation occurs exactly when conditions leading to the formation of ground-level ozone are at their worst. This is the type of use that would be allowed under EPA’s modified definition of emergency stationary RICE.”

Delaware’s serious concerns are warranted. While EPSA does not presently know the range of environmental emissions of BTM Generation, such information should be collected, calculated and analyzed before going down the path of increasing such BTM Generation by paying it as if it were a DR resource. There is a glaring lack of information on the extent of the situation, e.g., what types of generation comprise BTM Generation or what amounts of generation are implicated. Even Delaware, in assessing the impact of EPA’s action on the state, could only find and reference data compiled for the Northeast region in 2003 in the NESCAUM report. At a high level, as noted above, this rush to promote BTM Generation may result in the disintegration of centrally dispatched, organized markets, the model deemed to be the most efficient and reliable for serving consumers. More narrowly, these concerns clearly warrant the Commission to take a step back, hold the above-captioned Order No. 745 compliance proceedings in abeyance, and actually develop a factual record on the many implications of the proposed DR regime that were raised in the comments on the NOPR, but were not addressed at all in the Final Rule.

55 The Delaware Department of Natural Resources and Environmental Control's Petition for Reconsideration at 5, EPA Docket No. EPA-HQ-QAR-2008-0708 (April 30, 2010).
56 Id. at 3.
Clearly there are disagreements on the impacts of Order No. 745 and the implementation thereof in the instant ISO/RTO compliance filings on markets, consumers, the economy and even the environment. This is one of the many reasons why EPSA urged the Commission not to issue any final rule or regulation before it had addressed the many concerns and open questions that were raised by EPSA and others in their comments on the NOPR. These questions and concerns were either not addressed at all, or not addressed adequately, in the Final Rule. Therefore, at this point, EPSA again implores the Commission to address the concerns raised throughout the rulemaking proceeding and in rehearing motions by numerous stakeholders representing every sector of the electricity industry, before permitting any of the ISO/RTO compliance filings to become effective.
III. CONCLUSION

WHEREFORE, for the foregoing reasons, EPSA respectfully requests that the Commission consider these comments and this answer in the above-captioned compliance proceedings. The Commission should hold all of the above-captioned compliance proceedings in abeyance, until after it has acted on the pending requests for rehearing and/or clarification of Order No. 745. The concerns raised in these requests address issues directly impacting how ISOs/RTOs should comply with the Final Rule, including those addressed in these comments, as well as the very foundation of the compensation mechanism mandated by Order No. 745.

Respectfully submitted,

[Signature]

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the comments via email upon each person designated on the official service list compiled by the Secretary in this proceeding.


______________________
[Signature]

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Customers will participate in grid of the future

Major Trend #1:
Global proliferation of distributed energy resources:

- Solar
- Electric vehicles
- Distributed generation
- Smart buildings

Major Trend #2:
Power Grid will evolve from centralized command and control to distributed interconnected systems that are:

- Inter-coordinated
- Self-scheduling
- Self-healing

By enabling the seamless integration of distributed resources, smart loads and microgrids as Virtual Power into real time power grid operations, we can strengthen the reliability of the grid.
Keeping the Electric Grid in Balance is our most important priority.

One of the most important elements of a secure, integrated electric grid is ensuring that the consumption and production of energy is balanced every moment of every day. This means that supply of energy must equal instantaneous demand.

Historically, an increase in power demand has been met by generators producing electricity to supply into the grid.
New Regulations Have Created Opportunities for Energy Users

FERC 745 allows customer participation in capacity, energy and ancillary markets—allowing large energy users to play an equal role to that of traditional generators. That can result in substantial value for all consumers.

• For example, for the 2012-2013 year, the PJM clearing price would have been $391 per MegaWatt Day without demand response and energy efficiency in the capacity market.
• With demand response and energy efficiency, the clearing price was $245 per MegaWatt Day.
  • For New Jersey, that translated to $1.1 BILLION in savings to customers in just one year.
ORDER 745 RECOGNIZES THE REALITIES

• Intelligence is migrating to the edge of the grid, similar to telecom.

•* Electricity is a unique product - instantaneous balance required.

• A decrement of load balances the grid just like an increment of generation.

• A decrement of load has the same marginal value to the grid as an increment of generation.

• Load management is a service provided to the grid.
Effects of Order 745

- A more competitive grid - market power; market concentration.
- A more efficient grid - higher cost resource is displaced by lower cost resource.
- Lower prices (net benefits test). - FERC responsibility (J&R rates)
- Greater reliability.
- Pro-active consumers.
The Law

- Federal Power Act
  - Practices affecting jurisdictional rates.
  - Capacity market examples.
  - FERC can acknowledge in its Orders practical realities; not bound to text-book abstractions.
Customer Successes

One Day in July: How Viridity Optimizes Distributed Resource Economic Value

July 16, 2010

- Load Reduction - 622.83 kWh

15% Reduction with a 2 degree temperature increase as controlling action
Electricity Markets – Demand Response

Pepco Holdings, Inc.:
- Owns and operates three electric distribution companies, Potomac Electric Power Company, the Delmarva Power & Light Company, and the Atlantic City Electric Company
- Operates within the PJM Regional Transmission Organization
- 1.9 million distribution customers
- Combined peak load in excess of 13,000 MW
- Regulated by Delaware, District of Columbia, Maryland, and New Jersey Commissions
- Increasing mass market Demand Response resources

Demand Response
- PHI supports regulatory policies which encourage reliable Demand Response activities that are fairly compensated
- Electricity consumers will ultimately bear the costs of all Demand Response resources
- Smart grid technology will help Demand Response resources to further evolve
Demand Response Market Principles

1. Economic DR market compensation should be market based
2. Incentives that exceed market prices should be limited
3. All DR market revenue streams should be considered
   - Energy
   - Capacity
   - Ancillary Services
4. Long-run reliability impacts must be considered when revising the DR market framework
5. Costs should be fairly assigned across all market participants
6. Economic Demand Response should encourage the adoption of innovative technologies that enable new programs that can improve electricity market efficiency
   - Such as AMI enabled innovative pricing programs: dynamic pricing, real time pricing, and smart technologies that directly respond to grid conditions
7. Market rules should be transparent to all participants
Where we are, Where we want to Go, and Problems to Avoid

• Where we are…
  – Demand response providers receive full LMP provided that they perform and a net benefits test is passed
    • It is very important to get the net benefits test right
      – If the test result comes in too high then demand response will be under incented and likely under produced.
      – If the test result is too low then demand response will be over incented and too much DR will be consumed
    – Net benefits test must be transparent to all market participants

• Where we want to go…
  – Current demand response programs should serve as a stepping stone to long run programs that rely upon innovative technologies and run without complex rules that are easy for all consumers to participate in
  – Retail electricity prices that more directly track electricity market conditions

• What needs to be avoided…
  – DR markets that are not based upon the market
  – Programs or rules that over or under incent DR
  – Net benefit test results that miss the mark and generate resistance to current and future programs from program providers and/or consumers
NOTES
Capacity Markets
Energy Bar Association
RTO/ISO Seminar

Capacity Markets Overview

April 25, 2012

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Developed Capacity Markets in the U.S.

- The Evolution of Capacity Markets
- The Markets
  - New York ISO
    - Installed Capacity Market (ICAP)
  - PJM
    - Reliability Pricing Model
  - ISO New England
    - Forward Capacity Market (FCM)
- Their Characteristics
  - The First Sloped Demand Curve
  - Net CONE
  - Locational Prices
  - Term of Capacity Markets
- Market Power & Mitigation
  - Supply Side
  - Buyer Side
Early ISO Capacity Markets – Naturally Occurring Vertical Demand Curves

- In times of surplus, prices plummet
- In times of shortage, prices spike
- Boom-bust cycle

Prices and capacity requirements are established based on how much locational capacity bids in under the curve.
What is Net CONE?

- All in cost of new entry
  - Location specific
  - Usually a gas fired peaker or combined cycle unit

- Less

- Net Revenues
  - Energy Sales
  - Ancillary Service Sales
  - Other Sources (Incremental TCCs/FTRs)

- Converted into Net CONE ($/KWy or KWM)
Capacity Prices Vary by Location

CAPACITY PRICES VARY BY LOCATION

- Location A
- Location B

PRICE$/KWY

INSTALLED RESERVE

115%=IRM
Due to transmission constraints into certain localities, areas or zones, some LSEs must procure a substantial portion of their ICAP/UCAP requirements from local resources.
Timing Varies by RTO

- **NYISO**
  - Three year Demand Curves
  - Auctions are Capability Period or monthly just before the Capability Period or month

- **PJM/ISO-NE**
  - Auctions are held three years forward
Market Power Mitigation
Under supplier side mitigation, critical suppliers may not withhold capacity
**Context of Capacity Market Buyer Side Mitigation**

- Due to political will, energy prices have been and are substantially mitigated to prevent violent scarcity pricing from occurring.

- In large part to respond to the decrease in energy market revenues, in 2003, FERC approved the first capacity market predicated on a demand curve based on the concept that capacity market prices should equal the all in cost of new entry (CONE) less net revenues from energy and ancillary service sales when the market is approaching equilibrium, the state when supply equals peak demand plus the installed reserve requirement.

- Recently, FERC has been modifying the capacity markets so that uneconomic entry is discouraged.

  - An example of uneconomic entry would be when a utility contracts for bilateral supply from a new resource at prices above the market prices, but in order to cause a decrease in the capacity market clearing prices that apply to more substantial load. It is economically rational for a utility to pay too much for 1,000 MW of incremental supply if it appreciably lowers its cost of serving 9,000 MW of load through a decrease in capacity clearing prices.
Buyer side mitigation is supposed to prevent a new uneconomic unit from participating in the capacity market and causing a decrease in capacity prices. FERC recently issued orders on PJM, ISO-NE and NYISO buyer side mitigation rules.

The revised buyer side mitigation rules adopted in the RTO/ISOs will likely prevent some new capacity from participating in the capacity market for several years or longer, thereby preventing an otherwise predictable decrease in capacity market clearing prices. This will be good for incumbent generators and new entrants that are eligible for exemptions from mitigation because they are actually economic. This will be bad for new entrants that are mitigated and cannot clear the market.
Buyer Side Mitigation

NYISO ICAP
Buyer Side Mitigation

New FERC Rules –Buyer Side Mitigation - NYISO

- **November 26, 2010 Order** - NYISO

On November 26, 2010, FERC issued an order addressing NYISO’s buyer side mitigation provisions for the installed capacity market in New York City. Pursuant to the NYISO’s in-City buyer-side mitigation measures, unless exempt from such mitigation, in-City ICAP suppliers that enter the capacity market must do so at a price no lower than the applicable offer floor set for the proxy unit net CONE (75% of Net CONE) or each suppliers’ unit-specific net CONE.

The order also addressed the duration of the offer floor: FERC accepted an offer floor duration methodology that provides that only the Installed Capacity that clears in 12 months (not necessarily consecutive) will cease to be subject to the offer floor. FERC rejected NYISO’s proposed minimum period of mitigation, finding that a specified minimum mitigation period is not needed.
The order also addressed the NYISO’s proposed offer floor exemption process. FERC accepted NYISO’s proposal to make an exemption determination on all potential new market entrants, regardless of whether an exemption test is requested. FERC also accepted a revised exemption test that was based on the average ICAP spot market price during each month of the two starting capability periods. Finally, FERC found it unreasonable to impose an offer floor on an entity whose resource was predicted to be economic at the time of construction, but was unable to clear the capacity auction due to unexpected change in market conditions.

On August 2, 2011, FERC issued an order denying rehearing or clarification of the November 26, 2010 Order.
Buyer Side Mitigation

New FERC Rules – Buyer Side Mitigation – Complaints Against NYISO

Complaints Against NYISO
- June 3, 2011 Complaint
- July 11, 2011 Complaint
Buyer Side Mitigation

New FERC Rules – Buyer Side Mitigation – Complaints Against NYISO

- June 3, 2011 Complaint
  - On June 3, 2011 in Docket No. EL11-42, Astoria Generating, TC Ravenswood and certain NRG Companies filed a Complaint against NYISO alleging that NYISO was interpreting the buyer-side mitigation rules of its currently-effective tariff in a manner that was unjust and unreasonable.

  - The Complainants allege that NYISO intends to make exemption and offer floor determinations in a manner that violates the services tariff and is inconsistent with FERC’s orders and the Demand Curve reset methodology. They also argue that that NYISO's mitigation exemption testing and offer floor processes are inappropriately opaque and secretive.
June 3, 2011 Complaint (continued)

- The Complainants also identify five specific alleged flaws in NYISO's implementation of the buyer-side mitigation rules:
  - NYISO intends to calculate Unit Net CONE without reflecting inflation costs that a new entrant will face
  - NYISO intends to project future capacity prices based on an outdated demand curve for purposes of conducting its mitigation exemption test
  - NYISO intends to use an outdated default bid value in conducting its mitigation exemption test
  - NYISO does not intend to adjust the default bid prong of the offer floor over time in tandem with changes to the ICAP demand curves
  - NYISO has abdicated its responsibility to review contracts necessary to accurately calculate Unit Net CONE

- The EL11-42 Complaint is limited to the NYISO's implementation of the currently-effective rules (which became effective on November 27, 2010).
- Several parties filed answers and protests to the complaints; FERC has not yet acted.
July 11, 2011 Complaint

- On June 29, 2011, the NYISO published the results of its July 2011 ICAP Spot Market Auction, which included the participation of the new Astoria Energy II ("AEII") project. The July 2011 Auction saw a 50% decrease in market clearing price relative to the prior month's auction. Astoria Generating and TC Ravenswood filed a second complaint in Docket No. EL11-50 on July 11, 2011, alleging that NYISO made an erroneous mitigation determination with respect to AE II and that AE II is either unmitigated or grossly under-mitigated. The Complainants further allege that Bayonne Energy Center ("BEC") was improperly granted an exemption from mitigation.

- The New York installed capacity strip auction for summer 2012 yielded an $11.70/kW-month price in New York City
Neither project is believed to have been tested under the buyer-side mitigation rules that existed prior to November 27, 2010. On an interim basis, Complainants request that any exemption granted to AE II and BEC be immediately revoked at that both projects be subject to an offer floor of 75% of Mitigation Net CONE during the pendency of the Complaint. On a prospective basis, they request that the NYISO be required to re-test AE II and BEC for exemption and offer floor determinations. The Complaint is still pending before FERC.

- BEC defended its exemption based on the very low (relative to the proxy unit) Net CONE. Efficient, competitive new entry should not be stymied.
Buyer Side Mitigation

PJM RPM
In an order issued on April 12, 2011, FERC approved a rate filing by PJM to modify the minimum offer price rule ("MOPR") to prevent uneconomic entry of new generation. FERC reviewed whether PJM’s proposed revisions were necessary to ensure that the MOPR applies appropriately to resources that may have incentives to submit bids below their actual entry costs.

FERC found that the appropriate duration for the MOPR offer floor is that the offer floor should apply to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market, and accepted PJM’s proposal to apply the MOPR to CTs and CCs but not to exempted resources.

FERC also accepted PJM’s reference values as the relate to Net CONE and accepted PJM’s proposal to raise the conduct screen to 90% of Net CONE.

FERC additionally accepted PJM’s proposal to eliminate its net-short requirement, agreeing that the net-short requirement is ineffective and unnecessary. FERC also accepted PJM’s proposal to eliminate the impact screen and delete the MOPR sunset provision.
Buyer Side Mitigation

ISO-NE Forward Capacity Market
Buyer Side Mitigation

ISO-NE Forward Capacity Market

- April 13, 2011 Order² – ISO-NE
  - In an order dated April 13, 2011, FERC addressed issues in connection with ISO-NE’s Forward Capacity Market and ordered ISO-NE to develop an offer floor mitigation “construct” similar to that of PJM and NYISO in order to deal with Out of Market (“OOM”) resources suppressing clearing prices below competitive levels. FERC ordered ISO-NE to address offer-floor mitigation through the stake holder process.

  - In an order dated January 19, 2012, FERC accepted the May 13 and August 22, 2011 compliance filings by ISO-NE. The compliance filings established that the revisions required by the April 13 Order will be implemented in two stages, prior to the qualification dates for the seventh and eighth Forward Capacity Auctions. Revisions include changes to the OOM and the Alternative Price Rule, elimination of CONE, elimination of auction floor price, implementation of a MOPR process, and modeling zones “all the time”.

SNR DENTON
The Future of Capacity Markets

The awkward state of “reflective equilibrium” guided by a “veil of ignorance.”

- John Rawls, A Theory of Justice

• Now to our expert panel…
Questions for the Panel

- Will capacity markets help solve for potentially accelerated need for new capacity as a result of plant retirements hastened by Federal and State regulation?

- Are capacity markets sending transparent and efficient price signals to ensure new capacity will be developed where and when needed?
  - If not, how should the regulators and the ISOs address the problem/improve the markets?
  - Is there room for a truly bilateral capacity market or state programs to ensure capacity is built where and when needed?

- In developing unit-specific offer floors and determining whether a unit is subject to buyer-side mitigation, is one market participant's uneconomic entry another market participant's good faith business model?

- Are we destined to a system in which every major mitigation determination will be the subject of litigation and years of uncertainty?
Endnotes


2. ISO New England, Inc. and New England Power Pool Participants Committee, ORDER ON PAPER HEARING AND ORDER ON REHEARING, 135 FERC ¶ 61,029 (Issued April 13, 2011)
Current Issues Facing RTO/ISO Capacity Markets

Paul Flynn, Shareholder
April 25, 2012
Overview

• RTO Capacity Markets
• Minimum Offer Price Rule
• Intent
• Self-Supply
• State Exemption
• Other Exceptions
RTO Capacity Markets

• Foundation of regional approaches: installed capacity requirements on LSEs to minimize likelihood of a loss of load.
• E.g., LSE must show installed capacity equal to its peak loads plus reserves, or pay penalty typically based on cost to build new peaker.
RTO Capacity Markets (cont’d)

• ISO-NE, NYISO, and PJM have evolved to single-clearing price, forward, locational capacity auctions to meet this need; MISO proposing to go in this direction.
• Capacity auctions intended to send price signal of need for new capacity, and to reflect cost to build new capacity where and when needed.
RTO Capacity Markets (cont’d)

- Economic theory: price in competitive market set by avoided cost of last seller needed to clear the market.
- FERC: even if market structurally non-competitive, mitigation (e.g., offer caps at avoided cost) ensures competitive outcomes, *PJM*, 121 FERC Para. 61,173, at P24 (2007) See also *Blumenthal v FERC*, 552 F.3d 875 (D.C. Cir. 2009).
- Capacity markets often concentrated: existing capacity in given area controlled by few sellers; addressed through supplier market power mitigation rules, e.g., avoidable cost offer caps for existing resources.
RTO Capacity Markets (cont’d)

- When capacity is short, RTO auctions set price based on estimated cost of peaker, similar to old construct, but with sloped demand curve (PJM and NYISO) or descending clock auction (ISO-NE).

- Signals need for new capacity based on estimated cost of new marginal unit.

- If capacity short and actual new resource offers at its expected net cost, that offer will determine the clearing price, at actual cost to add capacity.
MOPR Rationale

• If bidding “too high” is mitigated, should bidding “too low” be mitigated?
• FERC: if new entry plant offers into auction at low net cost not due to efficiency but due to revenues outside regional market not available to other potential new entrants, capacity auction price will be suppressed.
• Such an offer can be mitigated, i.e., rejected or revised upward.
MOPR Rationale (cont’d)


• FERC has found that price suppression:
  – deters entry by suppliers without out-of-market (“OOM”) revenues
  – shifts costs to captive customers
  – defeats mkt goal b/c not competitive price
Intent

• FERC has made clear that intent to suppress price need not be shown.
• ISO-NE, 135 FERC ¶ 61,029, at P 170: out of market “capacity suppresses prices regardless of intent.”
• NYISO, 124 FERC 61,301, at P 29 (2008): “all uneconomic entry has effect of depressing prices below competitive level.”
Intent (cont’d)

• PJM and NYISO first included “net short” rules to focus on sellers with presumed bad intent; FERC later approved deleting those rules.
• MISO proposes in its resource adequacy filing in Docket No. ER11-4081 that its IMM must prove to FERC that offer is attempt to suppress price; MISO’s IMM commented in opposition to that requirement.
Self Supply

• FERC has rejected MOPR exception for self-supply (offering at zero price).

• *PJM*, 135 FERC ¶ 61,022, at PP 193,195: Self-supply new entry offers at zero price:
  – “create an environment in which only such self supply investment will occur.”
  – “significantly impede competition from all types of private investment and shift long-term investment risk from private investors to captive customers.”
  – Therefore, new self-supply “must compete with other planned generation on the same competitive basis.”
Self-Supply (cont’d)

• Parties in PJM case argued on rehearing that imposing MOPR on self-supply:
  – treats long-standing capacity procurement practices as improper price suppression;
  – creates risk that self-supply resource will not clear auction, and raises prospect of LSE double-payment for capacity: once thru self-supply, and again thru capacity market charges.
Self-Supply (cont’d)

• FERC on rehearing, 137 FERC ¶ 61,145, denied blanket exemption for self-supply:
  – For capacity prices to elicit new entry when needed, “offers submitted into PJM’s capacity auctions must accurately reflect avoidable net costs.” (P 205)
  – Found that new self-supply resources “may not generally have the incentive to bid their true avoidable net costs into PJM’s capacity auctions,” so denied blanket self-supply exemption.
  – But changed case-specific exception process to help address self-supply clearing concerns. (P 209)
Self-Supply (cont’d)

• MISO July 2011 resource adequacy filing proposes complete exception for self-supply from MOPR; MISO IMM opposes that.
• MISO also proposes LSE “opt-out” from capacity auction, including partial opt-out (functional equivalent of zero offer in auction).
• PJM has opt-out program but only for full load in defined area (no part-in; part-out) and LSE must opt out for five years. FERC cited PJM opt-out plan as possible means for LSE to do self-supply without triggering MOPR.
State Exemption

- Original PJM MOPR included exception for project approved in state process to meet capacity shortage; FERC MOPR Order approved deletion of that exception; FERC also denied NYPSC request for state exception to NYISO MOPR.

- New law in NJ precipitated 2011 PJM MOPR changes: law provides for NJBPU to select new generation for NJ; selected unit must offer in such a way that it clears PJM auction; NJ ratepayers would pay difference between new plant costs and PJM auction revenues.

- ISO-NE allegedly has large overhang of “OOM” capacity similarly selected through state process; claimed to suppress ISO-NE capacity auction prices.
State Exemption (cont’d)

• *PJM* Order, 135 FERC 61,022, holds that states are free to pursue policy goals by financing new investments but must submit bids into capacity auction consistent with their competitive costs.
  
  – “no valid state interest in ensuring that uneconomic offers can submit below-cost offers into the [capacity] auction.” (P 142).
  
  – “without effective mitigation of state-sponsored uneconomic entry, actions of a single state could have the effect of preventing other states from participating in the wholesale markets.” (P 143).
Other Exemptions

• Two types of exemptions:
  – Categorical
  – Case-specific review process

• Categorical, e.g., resource type, previously cleared, self-supply.

• Exemption review process:
  – Sell offer below minimum price screen based on generic estimate;
  – RTO or IMM reviews seller’s estimated unit-specific net costs.
Other Exemptions (cont’d)

• FERC-approved case-specific MOPR exception process for PJM “recognizes varying long-standing business structures and practices while also protecting against attempts to exercise buyer market power.” 137 FERC 61,145, p 244 (2011).

• Sell offers must be “consistent with” competitive cost of new entry were the resource to rely on PJM market revenues, but need not adopt every assumption of the reference resource.

• FERC found that evaluating whether a revenue source is of the type “customarily enjoyed by the type of seller” and pre-existed RPM, is a more objective standard than whether a cost or revenue is simply “competitive.”
Questions?

For more information, please contact:

Paul Flynn, Shareholder
flynn@wrightlaw.com
202-393-1200
EBA RTO/ISO Seminar

Glen Thomas
P3 Group
April 25, 2012
PJM Power Providers Group (P3)

- Non-profit 501 (c) (6) Delaware Corporation founded in 2007 (5 years ago).
- Dedicated to properly designed and well-functioning markets in the PJM region.
- 87,000 MW’s, 51,000 miles of transmission and 12.2 million customers.
- 12 members.
- www.p3powergroup.com
RPM is keeping the lights on.
Demand response has emerged as a material capacity resource.
Prices have been consistent with market conditions.
Transmission capacity is a huge driver of RPM prices.
RPM is politically charged.

5 Lessons Learned
RPM does not incent new generation.
RPM only benefits incumbent generators.
RPM encourages “old, dirty” plants to stay on line.
RPM prices are too high.
The lights are going out in Maryland unless the PSC intervenes in the market.
Challenges of the Next 5 Years

- Political Interference
- Transition of the Generation Fleet
- Demand Response
- Volatility
- Interface with Transmission Planning
What about the next five years?

- Incremental changes to RPM.
- FERC remains resolute.
- Retail competition expands.
- Political winds continue to blow.
- Technology advances.
- Consumers win if their regulators let them.
An In-Depth Look at RTOs and ISOs: Capacity Markets

Energy Bar Association, April 25, 2012

Jay Morrison
VP-Regulatory Issues
National Rural Electric Cooperative Association
(703) 907-5825 jay.morrison@nreca.coop

* With many thanks to the fair-use doctrine
Dave... I’m afraid I can’t let you do that...
PJM MOPR Dispute

Dkt. Nos. ER11-2875, EL11-20
Centralized Market Model

Traditional Model
How the hybrid worked:

The RPM, defining the terms of the “Base Residual Auction” served to “enable commitment of capacity resources needed to satisfy remaining capacity needs of LSEs after taking account of their owned and contracted resources”  

1) Guaranteed clearing for self-supply
2) An acceptable offer price = Cost - Revenue
FERC recognized the value of the hybrid

In approving the RPM, the Commission “conclude[d] that after LSEs have had an opportunity to procure capacity on their own, it is reasonable for PJM to procure capacity in an open auction at a time when further delay in procurement could jeopardize reliability. This however should be a last resort.”

Value of the hybrid

“Long term power contracts are an important element in a functioning electric power market. Forward power contracting allows buyers and sellers to hedge against the risk that prices may fluctuate in the future. Both buyers and sellers should be able to create portfolios of short, intermediate, and long-term power supplies to manage risk and meet customer demand. Long-term contracts also improve price stability, mitigate the risk of the abuse of market power, and provide a platform for investment in new generation and transmission.”

Traditional Model

Centralized Market Model
Centralized Market Model

Traditional Model
How the thumb works

RPM becomes the only game in town:

1) Guaranteed clearing for self-supply
2) An acceptable offer price = Cost - Revenue
How the thumb works

1) Guaranteed clearing for self-supply
2) An acceptable offer price = Cost - Revenue

Costs proposed to be adjusted upward to reflect “market” cost of capital and short depreciation period of IPPs
How the thumb works

1) Guaranteed clearing for self-supply
2) An acceptable offer price = Cost - Revenue

Revenue proposed to be adjusted downward to reflect only PJM’s estimate of the revenues available from sales into PJM’s centralized markets during the short depreciation period
How the Thumb Works

• Revenue from retail consumers is presumed abusive
• Revenue from bilateral sales is presumed abusive

-- “[T]he object of the MOPR review is to determine the offer that a non-market sponsor [a developer with retail or bilateral sales] would offer if they were making a competitive offer.” Motion for Clarification of the IMM for PJM (Feb. 2012).

-- “Competitive offers are based on actual costs, without non-market revenues, which will succeed or fail in the market based on its offer.” Motion for Clarification of the IMM for PJM (Feb. 2012).

-- “Projects built by rate-based entities, or otherwise supported by non-bypassable retail rates, shall be assumed to fail the [conduct] screen.” P3 Complaint, Exh. 1 at 5 (Testimony of Dr. Shanker).
How the Thumb Works

• Long-term planning and long-term contracts are presumed abusive
  -- Motion for Clarification of the IMM for PJM (Feb. 2012) (arguing that project sponsors should not be permitted to presume plant life longer than 20 years)

• Considerations other than short-term centralized market prices are unacceptable:
  -- “RPM itself, however, has no feature to explicitly recognize, for example, environmental or technological goals, nor does it contemplate reliability concerns beyond a three year forecast.” -- *PJM Interconnection, L.L.C.* 137 FERC P 61, 145 at P 90 (Nov. 2011) (In the order approving elimination of clearing guarantees for self-supply and state requirements that allowed LSEs and regulators to reflect exactly those considerations in their economic analyses)
How the Thumb Works

• Market prices are not permitted to reflect surplus capacity

--P3 proposes to establish minimum bids for all resources in the market at the CONE for a combustion turbine
What would this philosophy mean both within and outside RTO regions?
The customer can have any color he wants so long as it's black.
You may have any kind of market you want, so long as it’s a short-term centralized market in which everyone looks like an IPP.
In the end, FERC accepts a new hybrid

- “[W]e agree with PJM and those intervenors who argue that well-recognized business models should not be considered automatically suspect when determining whether a sell offer accurately reflects avoidable net costs” -- *PJM Interconnection, L.L.C.*, Order on Compliance Filing etc., 137 FERC P 61,145 at P.5 (Nov. 2011)

But

- Requires that the seller show in a unit-specific review that its proposal is “consistent” with a “competitive” bid relying solely on PJM market revenues
Risk Ultimately Hurts Consumers
Oh, well. Back to the drawing board
Disclaimer

- Capacity Market issues are often interesting, important, and controversial.
- Views expressed and interpretations offered here today are solely mine, not the NYISO’s.
Evolution of NYISO’s Rules

- NYPP origins and ConEd divestiture
- 2000 -- “Transitional” Market Design
- 2001 -- “Permanent” Design (UCAP/EFORd)
- 2003 -- Sloped Demand Curves
- 2007-08 -- In-City Markets and Mitigation
- 2009 -- Forward Capacity Market Study
Differences Between NYISO and PJM

- Single State ISO & Unique NYC Issues
- No Forward Capacity Auctions
- Utilities have divested generation
- No History of RMR Contracts
- Recent disputes over implementation not design
- Less exposure to new EPA rules
Overview – Establishing Requirements

- NYSRC sets IRM
- NYISO sets ICAP/UCAP requirements
  - NYCA-wide and NYC/LI “Locations”/”Zones”
  - “New Capacity Zone” rules
- Individual LSE UCAP Requirements
Overview – Suppliers and Sales

• Supplier UCAP Ratings

• NYISO-Administered ICAP Auctions
  ➢ Capability Period
  ➢ Monthly
  ➢ Spot Market -- ICAP Demand Curves

• Bilateral Sales
Vertical vs. Sloped Demand Curves

Figure 1: Vertical Demand Curve

Figure 2: Sloped ICAP Demand Curve
ICAP Demand Curves – Cont’d

• Three ICAP Demand Curves
  ➢ LI, NYC, and NY as a whole

• Triennial review process
  ➢ Update parameters and file revised curves
  ➢ Localized Levelized Cost of New Peaking Unit
  ➢ Filing in late 2010 was for May 2011 - April 2014
NYC Capacity Market Mitigation

• Supplier-side
  ➢ Offer Cap on “Pivotal Suppliers”
  ➢ Penalties for withholding

• Buyer-side
  ➢ Offer Floor for new entrants, prevent subsidized uneconomic entry
  ➢ Exemptions for entry that appears economic at time of investment decisions.
How Well Are the Markets Working?

• Many perspectives.
• 2011 MMU “State of the Market Report”
  ➢ Market performed competitively but with room for improvement.
  ➢ Prices fell 80% (35% in NYC) from 2010.
  ➢ Prices across all markets below level needed to attract new peaking generator.
  ➢ Results consistent with surplus conditions.
Current Issues

• In-City Capacity Market Power Mitigation
  ➢ “Legacy” In-City ICAP Issues
  ➢ 2011 Buyer-side Complaints – New Entry and Alleged “Artificial Price Suppression”
  ➢ “Going Forward Costs” Complaint

• SCR Participation Complaint

• Demand Curves
Looking Ahead

• Pending DC Circuit & Commission decisions
• RRCs/RMRs
• Other possible rule enhancements
• Capacity Market Design Study
• New Capacity Zones
• Future disputes over new entry?
References


- *NYISO Installed Capacity Manual* 

- NYISO ICAP “Event Calendar”  <http://icap.nyiso.com/ucap/public/evt_calendar_display.do>


References


- New York Independent System Operator, Inc. 137 FERC ¶ 61,218 (2011); 135 FERC ¶ 61,170 (2011); 135 FERC ¶ 61,002 (2011); 134 FERC ¶ 61,058 (2011) (Orders accepting the NYISO’s most recent triennial ICAP demand curve reset).
References

• New York Independent System Operator, Inc., 131 FERC ¶61,170 (major rehearing order on In-City ICAP Market investigation and market re-design).


• FERC Docket Nos. EL11-42 and EL11-50 (pending complaints by In-City generators re: the NYISO’s implementation of buyer-side mitigation).

• FERC Docket No. ER12-360 (Tariff revisions to govern the implementation of New Capacity Zones).
References

- FERC Docket No. EL12-58 (Pending complaint concerning NYISO’s calculation of GFCs for Astoria Generating Company)

- FERC Docket No. EL12-56 (Pending complaint concerning: participation of base load behind the meter generation in the SCR program)

- Recent presentation to stakeholders on possible RRC rules

- Draft Scope of Work for NYISO Capacity Market Design Study
Choosing a RTO or ISO
Helping our members work together to keep the lights on... today and in the future
SPP History & Organizational Structure
Our Beginning

- Founded 1941 with 11 members
  - Utilities pooled electricity to power Arkansas aluminum plant needed for critical defense
- Maintained after WWII to continue benefits of regional coordination
SPP Milestones

1968  Became NERC Regional Council
1980  Implemented telecommunications network
1991  Implemented operating reserve sharing
1994  Incorporated as non-profit
1997  Implemented reliability coordination
1998  Implemented tariff administration
2001  Implemented regional scheduling
2004  Became FERC-approved Regional Transmission Organization
2006  Implemented contract services
2007  Launched EIS market, became NERC Regional Entity
2009  Integrated Nebraska utilities
2010  FERC approved Highway/Byway cost allocation methodology and Integrated Transmission Planning Process
The SPP Difference

• Relationship - Based
• Member - Driven
• Independence Through Diversity
• Evolutionary vs. Revolutionary
• Reliability and Economics Inseparable
SPP at a Glance

• Located in Little Rock

• ~500 employees

• $139 million operating budget (2011)

• 24 x 7 operation

• Full redundancy and backup site
65 SPP Members

- Cooperatives: 14
- Municipals: 12
- State Agencies: 4
- Marketers: 10
- Investor-Owned: 7
- Independent Transmission Companies: 7
- Independent Power Producers / Wholesale Generation: 11
Members in 9 states

Arkansas
Kansas
Louisiana
Mississippi
Missouri
Nebraska
New Mexico
Oklahoma
Texas

Provide services to Entergy on contract basis (ICT)
Our Major Services

• Facilitation
• Reliability Coordination
• Transmission Service/Tariff Administration
• Market Operation

• Standards Setting
• Compliance Enforcement
• Transmission Planning
• Training

Regional
Independent
Cost-effective
Focus on reliability
2010 Wholesale Energy Market

- 32 participants
- 405 generating resources
- 2010 transactions = $1.28 billion
- 45 GW peak load
- 223 TWh energy consumption
- 16 Balancing Authorities
- 1,500 MW wholesale demand response
SPP Strategically

BUILD A ROBUST TRANSMISSION SYSTEM

DEVELOP EFFICIENT MARKET PROCESSES

CREATE MEMBER VALUE
SPP Governance

Southwest Power Pool
Facilitation: Helping our members work together
<table>
<thead>
<tr>
<th>Region</th>
<th>Regional State Committee (RSC)</th>
<th>Cost Allocation Working Group (CAWG)</th>
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</thead>
<tbody>
<tr>
<td>Arkansas</td>
<td>Commissioner Reeves</td>
<td>Pat Mosier</td>
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<tr>
<td>Kansas</td>
<td>Commissioner Wright</td>
<td>Tom DeBaun/James Sanderson</td>
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<tr>
<td>Oklahoma</td>
<td>Chairman Murphy</td>
<td>Trent Campbell</td>
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<td>Missouri</td>
<td>Chairman Gunn</td>
<td>Adam McKinnie</td>
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<td>Nebraska</td>
<td>Chairman Siedschlag</td>
<td>John Krajewski</td>
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<td>New Mexico</td>
<td>Commissioner Lyons</td>
<td>James Brack</td>
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<tr>
<td>Texas</td>
<td>Chairman Nelson</td>
<td>Temujin Roach</td>
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</tbody>
</table>
What role do state regulators play?

• Regional State Committee - Retail regulatory commissioners from:

  Arkansas    Nebraska    Oklahoma
  Kansas      New Mexico   Texas
  Missouri

  *Louisiana maintains active observer status*

• Primary responsibility for:
  – Cost allocation for transmission upgrades
  – Approach for regional resource adequacy
  – Allocation of transmission rights in SPP’s markets
## Who pays for transmission?

<table>
<thead>
<tr>
<th>Type</th>
<th>Reliability</th>
<th>Sponsored</th>
<th>Economic</th>
<th>Highway/Byway</th>
</tr>
</thead>
<tbody>
<tr>
<td>Funded</td>
<td>“Base Plan Funding”</td>
<td>Directly assigned w/ revenue credits</td>
<td>“Postage Stamp” for 345 kV projects with balancing transfers</td>
<td>Postage Stamp</td>
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<tr>
<td>Reason</td>
<td>Criteria or Designated Resource</td>
<td>Sponsor(s) nominate projects</td>
<td>Aggregate and Individual Transmission Owner Benefits / Cost ≥ 1</td>
<td>ITP projects</td>
</tr>
</tbody>
</table>

### Highway/Byway

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Paid for by Region</th>
<th>Paid for by Local Zone</th>
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</thead>
<tbody>
<tr>
<td>300 kV and above</td>
<td>100%</td>
<td>0%</td>
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<tr>
<td>above 100 kV and below 300 kV</td>
<td>33%</td>
<td>67%</td>
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<tr>
<td>100 kV and below</td>
<td>0%</td>
<td>100%</td>
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</table>
Integrated Marketplace – March 1, 2014
Why develop new markets?

• SPP conducts complex cost-benefit studies before beginning new market development
  – Under Regional State Committee oversight
  – 2005 Charles River Associates analysis of EIS market:
    • Estimated benefit of $86 million for first year
    • Actual benefit of $103 million for first year
• Integrated Marketplace will bring estimated annual average additional net benefits of $100 million
  – According to 2009 Ventyx analysis
  – March 1, 2014 launch
# Key Dates in Integrated Marketplace History

<table>
<thead>
<tr>
<th>Key Milestone</th>
<th>Completion Date</th>
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<tbody>
<tr>
<td>Begin Integrated Marketplace Business Design</td>
<td>Summer 2007</td>
</tr>
<tr>
<td>Cost-Benefit Analysis for Future Markets Completed</td>
<td>April 2009</td>
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<tr>
<td>RSC Endorsement of Cost-Benefit Analysis</td>
<td>April 2009</td>
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<tr>
<td>SPP Stakeholders developed detailed Market Design</td>
<td>2008-2010</td>
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<tr>
<td>MWG Finalized Baseline Protocols</td>
<td>September 2010</td>
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<td>MOPC Approval of Baseline Protocols</td>
<td>October 2010</td>
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<tr>
<td>Board Approval of Implementation Budget</td>
<td>January 2011</td>
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<tr>
<td>Board Release of Funds</td>
<td>April 2011</td>
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<td>SPP Contracted Vendors</td>
<td>May 2011</td>
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<td>Real-time Balancing Market solving</td>
<td>December 2011</td>
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<tr>
<td>Tariff Revisions filed at FERC</td>
<td>February 2012</td>
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Marketplace Timeline

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FAT: Factory Acceptance Test  | SAT: Site Acceptance Test  | FIT: Functional Integration Test  | PT: Performance Test
Creating, Joining, Changing or Leaving an RTO

John S. Moot
Overview

• Voluntary RTO participation creates challenges in four different settings:
  – Creating an RTO in a region where there is none
  – Joining an existing RTO
  – Changing between existing RTOs
  – Leaving an RTO altogether

• Several issues are implicated by these choices:
  – Market design
  – Jurisdiction (state and non-jurisdictional entities)
  – Cost allocation (entry and exit fees and/or waivers)
  – Contract rights (what is voluntary vs. what is required)
Creating an RTO

- This remains a choice in the West and Southeast
- Old (and continuing?) baggage
  - Distrust of markets
  - Jurisdictional concerns
  - Quantifying benefits versus costs
  - The long SMD/California crisis hangover
- Newer wrinkles and considerations
  - Energy imbalance market in the West?
  - BPA section 211A case
  - Entergy joining MISO in the Southeast
  - When market prices fall, people tend to like markets better
Joining an RTO

• Whether to join an RTO?
  – Benefits
    • Production cost savings
    • Access to larger geographic markets
    • Reduced compliance risk (OATT audits, investigations)
  – Concerns
    • Jurisdictional issues and state approvals
    • Cost allocation and cost shifts (e.g., transmission upgrades)

• Which RTO to join (if there is a choice)?
  – Relevant in Eastern Interconnect (PJM, MISO and SPP)
  – Different histories and orientations with respect to retail access, Day 2 markets and formal capacity markets
Changing from one RTO to another

- Cost and market considerations cause companies to continually evaluate their RTO options
- Prior examples of changes (or proposed changes)
  - Duquesne, FirstEnergy, and Duke
  - The “choices” of the Alliance Companies
- Key legal and policy issues
  - Does the company changing RTOs need to show benefits or hold others harmless from cost impacts?
  - What entry charges or exit fees should apply?
    - Current policy is not as clear as it should be
    - Recurring issue: cost causation versus beneficiaries pay
  - Interpreting the relevant contracts (e.g., TO Agreement)
  - Concerns regarding the instability of certain RTOs?
Leaving an RTO altogether

- Limited experience to date (LG&E)
- However, pressures can remain to justify continued membership (e.g., historic experience re Ameren)
- The good news for the supporters of markets is that RTOs have steadily expanded over time, rather than contracting
- Recurring issues with leaving an RTO
  - Exit fees
  - Contract rights
  - Post-RTO open access requirements
“You’ve Come a Long Way, Baby!”
The Evolution of MISO as an RTO
Lori Spence, Deputy General Counsel
April 25, 2012
MISO Evolution

Reliability Coordination & Tariff Administration

1996
- Discussions begin to form MISO
- Legislative Timeline: FERC issues orders 888/889
- 2000: FERC issues order 900
- 2001: FERC issues order 2000
- 2002: Tariff Administration under MISO’s Open Access Transmission Tariff
- 2003: Joint Operating Agreement with PJM
- 2005: Midwest Energy Markets Implemented

Market Implementation
Energy Market & Ancillary Services Market

2006
- 2006: Began Ancillary Services Market Initiative

Value Expansion

2009
- 2009: ASM Launch

2011
- 2011: Resource Adequacy
- 2011: Multi-Value Projects

- FERC approval as an RTO
- Reliability Coordination
Agenda – Key Points in MISO’s Evolution

• *Where We’ve Been*
  – Creation of MISO
  – Market Implementation

• *Where We Are: Current Scope of MISO Operations*

• *Where We’re Going: Value Expansion*
  – Resource Adequacy
  – Transmission Planning
  – Value Proposition
Creation of MISO: Regulatory Backdrop

• MISO was the product of an extensive regulatory backdrop:
  – Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, Final Rule, 75 FERC ¶ 61,078 (1996) (“Order No. 889”).
Order No. 888 (issued April 24, 1996)

– In Order No. 888, the Federal Energy Regulatory Commission (“FERC”):
  • Required public utilities to file open access non-discriminatory transmission tariffs; and
  • Permitted public utilities to recover stranded costs.

– Goal of Order No. 888: “Remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation’s electricity consumers.”*

– Order No. 888 encouraged development of independent system operators (“ISOs”)**

**JAMES H. McGREW, FERC: FEDERAL ENERGY REGULATORY COMMISSION 156 (ABA Publishing 2009).
Order No. 889 (issued April 24, 1996)

– **In Order No. 889, FERC:**
  
  • Required each public utility to implement standards of conduct to functionally separate transmission/wholesale power merchant functions; and
  
  • Required each public utility to create or participate in an Open Access Same-Time Information System (“OASIS”).
    
    – **OASIS**: Provides information about available transmission capacity, prices, etc.

– **Goal of Order No. 889**: “[Ensure] that transmission customers have access to transmission information enabling them to obtain open access transmission service on a nondiscriminatory basis.”*

*McGrew at 154.
Order No. 2000 (issued December 20, 1999)

– Sought to address certain problems that remained after Order Nos. 888 and 889.*

– In Order No. 2000, FERC:
  • Amended its regulations under the Federal Power Act to advance the formation of RTOs
  • Required each public utility to make certain filings with respect to forming and participating in an RTO
  • Codified minimum characteristics and functions for RTOs

– Goal of Order No. 2000: “[P]romote efficiency in wholesale electricity markets and ensure that electricity consumers pay the lowest price possible for reliable service.”**

*McGrew at 156.
**See Order No. 2000.
Minimum Characteristics of an RTO under Order No. 2000*

1. Independence
2. Scope and Regional Configuration
3. Operational Authority
4. Short-Term Reliability

*Order No. 2000 at pp. 151-323.
Minimum Functions of an RTO under Order No. 2000*

1. Tariff Administration and Design
2. Congestion Management
3. Parallel Path Flow
4. Ancillary Services
5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
6. Market Monitoring
7. Planning and Expansion
8. Interregional Coordination

*Order No. 2000 at pp. 323-497.
Designation of MISO as an RTO (2001)

- 01/16/01: MISO submitted Order No. 2000 compliance filing

- 12/20/01: FERC granted MISO RTO status, finding that it had satisfied all of the required characteristics/functions of an RTO under Order 2000.*

“We believe that a properly formed RTO in the Midwest will greatly benefit the public interest by enhancing the reliability of the Midwest electric grid and facilitating and enhancing competition. It will accomplish this primarily through standardization of the rates, terms, and conditions of transmission service over a broad region. With this order . . . we hope to help [MISO] achieve substantial benefits for Midwestern customers.”*

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MISO’s Market Implementation

• **Energy Markets (2005)**
  – Day-Ahead Energy Market
  – Real-Time Energy Market
  – Financial Transmission Rights Market (FTR)

• **Ancillary Services Market Initiative (ASM)** (2009)
Agenda – Key Points in MISO’s Evolution

• *Where We’ve Been*
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  – Value Proposition
MISO Scope of Operations*

• **Generation Capacity**
  – 131,010 MW (market)
  – 142,930 MW (reliability)

• **Historic Peak Load**
  (set July 20, 2011)
  – 103,9750 MW (market)
  – 110,032 MW (reliability)

• **49,641 miles of transmission**

• **11 states, 1 Canadian province**

• **5-minute dispatch**
• **1,911 pricing nodes**
• **1,242 generating units**
  (market)
• **5,930 generating units**
  (network model)
• **$23.6 billion gross market charges** (2011)
• **363 market participants**
  serving 38.9 million people

*As of January 1, 2012. For a copy of MISO’s Corporate Fact Sheet, see

MISO Market Footprint*

*As of January 1, 2012.
MISO Reliability Footprint

*As of January 1, 2012.
Agenda – Key Points in MISO’s Evolution

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Value Expansion: Resource Adequacy

• To achieve reliability, amount of resources (supply) must exceed demand by adequate margin

• Margins necessary to promote Resource Adequacy need to be assessed on both a near-term operational basis and on a longer-term planning basis:
  – Planning Reserve Margins—must be sufficient to cover planned maintenance, unplanned forced outages of generating equipment, etc.
  – Planning Resources—resources used to achieve long-term Resource Adequacy (i.e., Capacity Resources, Load Modifying Resources)

• MISO’s Resource Adequacy construct can be found in Module E of its Tariff.
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Transmission Planning: Order No. 1000

• On July 21, 2011, FERC issued its Final Rule, Order No. 1000, detailing planning and cost allocation for electric transmission facilities.*

• Building on Order No. 890, the Commission adopted a “principles based approach” that allows regional flexibility in meeting the minimum requirements of the rule.

Transmission Planning: Order No. 1000

• Four major components of Order No. 1000:*
  – Regional transmission planning requirements;
  – Interregional transmission planning requirements;
  – Transmission cost allocation principles; and
  – Elimination of the federal right of first refusal for facilities subject to regional cost allocation.

• Goal of Order No. 1000: “[T]o ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential.”

*See Order No. 1000 at pp. 67-779
MISO transmission planning is focused on achieving the proper balance of transmission and generation, to minimize the total cost of delivered power to consumers.

**Balancing Generation and Transmission Investment**

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**Goal:** Minimum total cost, energy, capacity and transmission

**Transmission Value Drivers:**

- Congestion and fuel savings
- Operating reserves
- System planning reserve margins
- Transmission line losses
- Wind turbine Investment
- Future transmission Investment
Transmission Planning: MTEP11

• MISO’s Transmission Expansion Plan for 2011, or MTEP11, recommends $6.5 billion in new transmission investment that collectively will: (1) maintain system reliability; (2) improve market efficiency; (3) enable public policy mandates; and (4) allow the reliable integration of new generation resources

• MTEP11’s Multi-Value Portfolio will create $15.5 to $49.2 billion in net present value economic benefits over a 20 to 40-year timeframe
The elements identified in the portfolio of Multi-Value Projects (MVPs) will work together with existing lines to relieve current constraints and allow delivery of low cost energy.
The portfolio of transmission elements will deliver between $6.7 and $32.8 billion of net benefits over the life of the assets.

**Multi-Value Project Portfolio**
- Total net benefit of $6.7 to $32.8 billion over a 20 – 40 year life
- Provides benefit / cost ratios of 1.8 to 3.0
- Provides annual value of $1.3 B vs. cost of $0.6 B
- Total portfolio construction cost of $5.2 billion
- 17 elements in the MVP portfolio
- Resolves 650 elemental reliability issues
- Enables 41 million MWh of wind energy
- Supports energy zones for both wind and natural gas
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Value Expansion: Value Proposition

• The annual Value Proposition study quantifies the value MISO provides to MISO market participants

• 2007-2011: studies revealed that the MISO region realized between $4.3 billion to $5.7 billion in cumulative savings

• 2011 Value Proposition: MISO Members received more than $2.2 billion in annual benefits from increased reliability, access to low-cost energy, and coordinated, long-term system planning
The MISO 2011 Value Proposition

Benefit by Value Driver\(^1\) (in $ millions)

1. Improved Reliability: $320-$479
2. Dispatch of Energy: $199-$219
3. Regulation: $176-$195
4. Spinning Reserves: $51-$56
5. Wind Integration: $163-$196
6. Compliance: $62-$93
7. Footprint Diversity: $526-$631
8. Generator Availability Improvement: $526-$631
10. MISO Cost Structure: $(248)

Total Net Benefits: $2,150-$2,708

\(^1\)Figures shown reflect annual benefits and costs that can be expected in 2011
Conclusion

• Membership has its privileges

• Value Drivers different for different business models

• MISO Cornerstones:
  – Operational Excellence
  – Customer Service
  – Effective Communication
NOTES
BIOGRAPHIES
Sean Atkins
Partner

Sean Atkins’ practice is focused on energy law, including federal and state regulation of electric utilities. He has extensive experience with legal and policy issues related to wholesale electricity markets, transmission planning and operations, and generator interconnections. Sean obtained approvals for new transmission planning procedures designed to facilitate the needs of renewable power. He served as chair of a working group of counsel representing utilities in the northeastern United States that successfully formed a regional transmission organization and attained incentive transmission rates.

Sean represents clients in administrative and appellate litigation and negotiates settlements of complex matters before utility regulators. He advises clients on the development of effective compliance programs and a variety of regulatory compliance issues.

Sean is part of Alston & Bird’s renewable energy practice, which focuses on a wide range of legal, regulatory, environmental and business challenges facing renewable power developers.


Sean received his J.D. in 1996 and his B.A. in 1991, both from the University of Virginia. He is listed in Chambers USA: America’s Leading Lawyers for Business.
Nancy Bagot
Vice President of Regulatory Affairs
Electric Power Supply Association

Nancy Bagot serves as vice president of regulatory affairs, focusing on the association's regulatory policy development and advocacy of federal and state issues affecting the development of a competitive wholesale energy market. Issues include the refinement of RTOs, ensuring fair and open access for all market participants to wholesale markets in all regions of the country, and the development of mutually reinforcing reliability standards and competitive market operations.


Bagot has represented the interests of the energy industry before the Federal Energy Regulatory Commission and other federal entities, focusing on electricity markets, natural gas and general policy. She has served as Chair and member of committees of the Interstate Natural Gas Association of America, as a member of the Keystone Dialogue on Natural Gas and Cleaner Power, and as a Board member of the Interstate Pipeline Regulatory Committee. She is currently a non-attorney member of the Energy Bar Association.

Bagot received a B.A. degree in English from Vassar College in Poughkeepsie, N.Y.
Stuart A. Caplan

Partner

Stuart Caplan has more than 20 years of experience in the energy industry and concentrates on electric and natural gas industry restructuring; renewable, fossil fuel and transmission project development; and the regulatory aspects of mergers and acquisitions.

Stuart has worked extensively with utilities in generator auctions producing proceeds in excess of US $3.5 billion and with bidders in several other auctions.

He has taken lead roles on creative transaction structures to enhance auction results and has effectively and timely secured federal transaction approvals.

He provides expert energy regulatory advice to lenders and investors and has worked on the following representative transactions:

- FPLE National Wind US $450 million bond financings (lead FERC counsel for underwriter).
- Counsel to an international energy company in connection with its proposed bid for Westinghouse. South Carolina Public Service Authority in its recent bid with Central Electric Cooperative to acquire an interest in the Catawba Nuclear Generating Station operated by Duke Power.
- Legal advisor to the New Jersey Board of Public Utilities' consultant in Exelon-PSE and G merger (US $13 billion). Hedge fund's acquisition of interests in Lake Road, La Paloma and Liberty generating project companies.
- MACH Gen transactions (lead regulatory counsel for four-station, 3,850 MW fleet). Joint venture to form Hess LNG (lead energy regulatory counsel for Amerada Hess). Lattice Group PLC's merger with National Grid (lead FERC counsel).
- Barclays Bank (lead bank) and the lender syndicate US $520 million project financing of the Iroquois Gas Transmission System. Power Market Formation and Energy

Representative Experience

- Stuart is a leading legal expert on power market formation. He has counseled market participants on new market structures in markets throughout the U.S. East Coast and Southwest.
- He was lead counsel in developing the NY Independent System Operator (ISO) tariff and lead FERC counsel for the Arizona Independence Scheduling Administrator.
- Stuart also was involved in negotiating the formation of the New England regional transmission organization (RTO).
- He advises clients on power market evolution and restructuring within the New England Power Pool, the NYISO, the Pennsylvania-New Jersey-Maryland Interconnection, the Southeast and the Southwest.
Stuart appears regularly before FERC and ISO committees and boards to press for market improvements.

He has assisted power marketers and ESCOs with power, transmission and retail wheeling transactions and agreements.

He was active in creating a multisector coalition in natural gas pipeline "comparable service" cases that led to the first "Mega-NOPR" and participated in many FERC natural gas pipeline cases.

Stuart is active in advising clients on liquefied natural gas ("LNG") and related pipeline projects. SMD, RTOs and Standards of Conduct (Order No. 2004): Stuart participated in FERC proceedings on Standard Market Design (SMD) and RTOs and was a leading advocate in the Northeast RTO Mediation at FERC (RTO1-99) and in negotiating agreements to form the NYISO and RTO-New England.

He has been on the cutting edge of electric reform since he led the Coalition for Economic Competition's legal efforts in FERC's Stranded Cost and Open Access proceedings (RM95-8 and RM94-7). The Coalition included eleven major energy companies.

Stuart advises clients on Order No. 2004 compliance and has a wealth of experience in FERC's Standard of Conduct and Code of Conduct requirements and related waiver applications.

Prior to joining SNR Denton, Stuart was an energy partner in the New York and Washington, DC, offices of White and Case.

In addition, he has chaired the regulatory department of a leading public utility law boutique and holds leadership positions in the energy bar.

Honors and Awards

- Ranked in *Chambers USA*, Nationwide, Energy: Electricity (Regulatory & Litigation), 2011
- New York City Energy Law Lawyer of the Year, *Best Lawyers*, 2012

Organizations

- Member, American Bar Association, Antitrust and Public Utilities, Telecommunications and Transportation Law Sections.

Publications


Presentations


Panelist, EEI Strategic Issues Conference "FERC's Standard Market Design: The Good, the Bad and the Ugly," Chicago, IL, Fall 2002.


Education

- American University Washington College of Law, 1985, J.D.
- Columbia University, 1982, B.A.

Bar Admissions / Qualifications

- New York
David T. "Dave" Doot – Partner

Professional Experience

David T. Doot is chair of the firm's Energy and Utility Law Department and practices in the areas of public utility and energy law. In these areas of law, Dave participates in mergers, acquisitions, and other related business realignments, has assisted in the development of generation and transmission projects throughout the United States. He assists industry participants in compliance-related efforts before federal and state regulatory agencies and represents clients in enforcement investigations before the Federal Energy Regulatory Commission. He negotiates and documents energy arrangements between and among industry participants for every type of energy project, including renewable energy projects. He has represented clients in proceedings before the Federal Energy Regulatory Commission, as well as in state regulatory proceedings throughout New England. He also counsels businesses around the country concerning wholesale and retail arrangements for the purchase and sale of electricity.

Dave is the past president of the now 2600-member Energy Bar Association.

Practice Areas

- Energy and Utility Law
- Renewable Energy

Representative Matters

- Serves as secretary and lead counsel for the New England Power Pool, the regional organization through which transmission service arrangements and wholesale power trading in New England have been defined; as general counsel to NEPOOL, the firm has prepared all of the amendments to NEPOOL arrangements, acquired the necessary regulatory approvals, and assisted in the mediation and settlement of numerous proceedings, including the settlement to implement a forward capacity market in New England
- Assisted in the purchase and sale of books of wholesale and retail contracts by energy market participants
- Advised industry participants in their purchases and sales of generation assets and companies
- Conducts negotiations on behalf of wholesale and retail electricity suppliers and purchasers

News, Publications & Presentations

- Co-author, "Keeping Your Kilowatts Private," Public Utilities Fortnightly, April 2012
- Co-author, "Using power purchase agreements to address uncertainty in offshore
- Quoted, "Nicor/AGL regulatory clearances not contentious, sources say," *dealReporter*, December 14, 2010
- Featured, "Fifty-seven Day Pitney Attorneys Recognized as Super Lawyers; Six Additional Lawyers Recognized as 'Rising Stars'," *Day Pitney Press Release*, November 12, 2010
- Day Pitney to Sponsor the Transmission Summit 2008
- Speaker, "Which Traditional Projects are Moving Ahead & Which are Dead or Dying?" *Energy in the Northeast Conference*, Boston, MA, October 18-19, 2007
- Co-author, "State Mandates Most Effective So Far in Renewable Portfolio Standards," *Natural Gas & Electricity*, July 2007
- Speaker, "FERC Market-Based Rate Standards for Wholesale Sellers of Electric Power in Interstate Commerce," *Fifth Annual Gas and Power Institute*, Houston, TX, September 28 & 29, 2006
- "'Forward Thinking' on Forward Contracts," *DBH Alert*, June 15, 2006
- "David Doot Named President of the Energy Bar Association," *DBH Press Release*, May 1, 2006
- "Landmark Energy Act Addresses Electricity Reliability, Transmission Concerns and Creates Additional Incentives for Renewable Sources of Energy and Nuclear Investment," *DBH Alert*, August 10, 2005
- Speaker, "NEPOOL Update," *Power Markets Conference*, Boston, MA, November 10, 2004
• Speaker, "Recent Developments in Electric Transmission and Power Marketing," Northeast Gas Association Executive Conference, Woodstock, VT, September 7-9, 2003
• "Benefit of Counsel: It's Time to Tally NOPR's Effects," Electric Light & Power, October 2002
• "Gen Interconnection: Lessons from New England," Public Utilities Fortnightly, September 15, 2002
• Speaker, "SMD NOPR," Massachusetts Department of Telecommunications and Energy, September 10, 2002
• Speaker, "SMD NOPR," Connecticut Department of Public Utility Control, September 3, 2002
• Panelist, "NEPOOL/ISO New England and Their Relationship," 2002 NECPUC Symposium, Stowe, VT, June 17, 2002
• "Making the Most of Deregulation," Energy Decisions, October 2001
• Speaker, "Lessons Learned in Retail and Wholesale Deregulation -- Doing it Different From California," California's Electric Restructuring Experience -- The Exception or the Rule, Chicago, IL, August 6, 2001

Education

• T.C. Williams School of Law, University of Richmond, J.D., magna cum laude, 1985, editor-in-chief, University of Richmond Law Review
• Cornell University, B.S., 1978

Admissions

• State of Connecticut

Professional Affiliations

• Energy Bar Association, board of directors and past President
• Connecticut Bar Association, Public Utility Law Section, executive committee
• American Bar Association, Public Utility Law Section

Outside Interests

• Past president and trustee of The Open Hearth Association, Hartford, CT
• Legal studies instructor, University of Hartford College for Women Entrepreneurial Center, Hartford, CT

Awards and Achievements

• Chosen for inclusion in the Chambers USA Legal Directory as a leading energy attorney, 2011
• Recognized as a Connecticut Super Lawyer, 2006-2011/2012
• Chosen for inclusion in The Best Lawyers in America, Energy Law, 2007-2012
• Chosen in The Hartford Area’s Best Lawyers as Energy Lawyer of the Year, 2011
Allen Freifeld, Senior Vice President, Law & Public Policy

Allen Freifeld joined Viridity as Senior Vice President, Law & Public Policy in June 2009, after twenty five years of regulatory and industry experience, including five years as a member of the Maryland Public Service Commission from 2004 through 2009. During his tenure on the Commission Mr. Freifeld led the effort to enhance the participation of energy efficiency and distributed resources in regional markets.

He served as Chairman of the Steering Committee of the Mid Atlantic Distributed Resources Initiative and was also a founder of the Organization of PJM States, Inc., a group of fourteen State Public Utility Commissions working toward regional solutions for electric grid issues.

Prior to his appointment to the Commission Mr. Freifeld served on the Staff of the Commission for over twenty years both as a Hearing Examiner and as Chief Staff Counsel. Mr. Freifeld also served as Chief Regulatory Counsel for MCI Telecommunications in the mid-Atlantic region during the period following enactment of the Telecommunications Act of 1996. Mr. Freifeld is a graduate of SUNY Binghamton, with a degree in Economics, and the University of Maryland School of Law.
Cynthia A. Marlette

Experience

Cynthia A. Marlette focuses her practice on energy matters, including Federal Energy Regulatory Commission regulation and related energy laws and policies.

Ms. Marlette has 30 years of experience in regulatory and policy issues affecting the nation’s energy industries. She served six years as the Federal Energy Regulatory Commission’s (FERC) general counsel and was responsible for providing legal and policy advice in all areas of the agency’s regulation, including: transmission and sales for resale of electric energy in interstate commerce; independent system operators and regional transmission organizations; reliability of the U.S. bulk power system; hydroelectric licensing and compliance; mergers and acquisitions of public utilities and utility holding companies; energy contract and tariff disputes; certification of cogeneration and small renewable power facilities; natural gas transportation and wholesale sales in interstate commerce; certification of natural gas pipeline projects and natural gas storage facilities; siting of LNG terminals; and FPA/NGA compliance issues.

In addition to twice serving as general counsel of FERC, Ms. Marlette held a number of other positions at the agency including principal deputy general counsel, associate general counsel and legal advisor to the chairman. As principal deputy general counsel, she directed the agency’s implementation of the Energy Policy Act of 2005, which involved over a dozen rulemakings under new authorities granted by Congress. Ms. Marlette also spent 10 years as associate general counsel for hydroelectric and electric matters and has extensive expertise in the Federal Power Act. She oversaw the drafting of Order No. 888, the FERC’s landmark 1996 rulemaking which opened up the nation’s electric transmission grid to non-discriminatory access and laid the foundation for competitive wholesale power markets, and participated in the rule’s successful defense before the United States Supreme Court.

Ms. Marlette has testified before numerous congressional committees on proposed energy legislation, including the Energy Policy Act of 1992, Public Utility Holding Company Act reform, and the Energy Policy Act of 2005. She has worked with congressional offices, diverse regulated entities, trade and customer groups, state agencies and commissions, and other federal government agencies on energy legislative and regulatory issues, and in resolving inter-agency conflicts. She also is an adjunct professor at the American University Washington College of Law, teaching regulation of energy.
Professional Affiliations

- District of Columbia Bar Association
- Energy Bar Association
- Foundation of the Energy Law Journal, Member – Board of Directors (2006-2009)

Awards and Honors

- Presidential Rank Award for Meritorious Executive in the Senior Executive Service from President George W. Bush (2008)
- FERC Chairman’s Medal for Leadership (2007)
- FERC Exemplar of Public Service Award (2005)
- Federal Bar Association’s Environment, Energy and Natural Resources Section and District of Columbia Chapter Certificate of Appreciation in recognition of outstanding public service (2005)
- FERC Award for Leadership Excellence (2001)
- Presidential Rank Award for Meritorious Executive in the Senior Executive Service from President Clinton (1997)
John Moot has served as lead trial lawyer in complex FERC litigation, argued cases in the U.S. courts of appeal and defended companies in enforcement actions. He has represented companies in high-profile mergers and acquisitions, including hostile takeovers, merger break-up litigation and generation asset swaps. Mr. Moot also has handled high-profile matters involving enforcement, market power, market design, transmission access, stranded costs, and RTO entry and exit decisions. According to Chambers USA 2009, Mr. Moot is “a master of strategy who commands respect.” Also, his “peers respect his thoughtful, measured and gentlemanly approach” noted Chambers USA 2010. Mr. Moot is considered “a go-to guy for ‘dissecting Commission policies, explaining what is wrong with them, and offering a roadmap of how to successfully change them’” noted Chambers USA 2011.

Mr. Moot served as general counsel (2005-2007) and chief of staff (2007-2008) of FERC. During his tenure at FERC, he played a leading role in FERC’s major policy initiatives, including implementation of the Energy Policy Act of 2005, open access transmission reform, reform of organized electricity markets, creation of a reliability regulatory structure and development of a post-EPAct enforcement program.

Mr. Moot is a leading author on energy regulation, with influential articles on reliability regulation, enforcement policy and compliance programs, transmission access reform and merger policy reform. Mr. Moot’s articles have appeared in the Energy Law Journal, The National Law Journal, the Administrative Law Review and Law360.
Mr. Morrison manages the Regulatory Issues Division of NRECA’s Government Relations Department, where he oversees a staff of professionals representing NRECA and its members on matters relating to federal and state utility regulation, power supply and delivery, and cooperative-law issues. Since joining NRECA in 1998, Mr. Morrison has focused extensively on issues relating to wholesale market design, power supply and delivery, industry restructuring, renewable energy, energy efficiency, distributed generation, and the smart grid.

In 1993, Mr. Morrison earned his MPP, from the John F. Kennedy School of Government and his JD, magna cum laude, from Harvard Law School. Mr. Morrison earned his BA summa cum laude from UCLA in 1989. Mr. Morrison has also clerked for the Honorable A. Raymond Randolph on the D.C. Circuit, served as counsel to the U.S. Senate Committee on Labor and Human Resources, and represented cooperatives and other clients before the Federal Energy Regulatory Commission, Congress, and the courts with the firm of Paul, Hastings, Janofsky & Walker.

Mr. Morrison and his wife Barbara Burgess live on a tiny farm in rural Virginia with their sons Abraham and Samuel and too many animals.
Commissioner John R. Norris

John R. Norris was nominated by President Barack Obama to the Federal Energy Regulatory Commission and confirmed by the U.S. Senate for a term expiring in June 2012.

Commissioner Norris, a lawyer, has years of experience in energy policy and regulatory affairs. He most recently served as Chief of Staff to Secretary Tom Vilsack of the U.S. Department of Agriculture. Prior to joining the USDA, he served as Chairman of the Iowa Utilities Board (IUB) from 2005 to 2009. During his tenure as IUB Chairman, Commissioner Norris served on the National Association of Regulatory Utility Commissioners (NARUC) Electricity Committee and was Co-Chair of the 2009 National Electricity Delivery Forum.

During his IUB tenure, Commissioner Norris also served as a Board Member, Secretary and President of the Organization of Midwest Independent System Operator (MISO) States as well as Chairman of the MISO Demand Response Working Group. He also was a member of the FERC/NARUC Demand Response Collaborative.

Commissioner Norris also has served on the Board of Directors of the National Regulatory Research Institute, as a member of the Board of Trustees of the Iowa Power Fund and on the Advisory Councils of the Iowa Energy Center, the Financial Research Institute for the University of Missouri College of Business and the Center for Global and Regional Environmental Research at the University of Iowa.

In 1999 and 2000, Commissioner Norris was Chairman of the Iowa Electric Restructuring Task Force while serving as Chief of Staff for then-Iowa Governor Tom Vilsack. He also served as Chief of Staff for U.S. Representative Leonard Boswell (IA-3rd) from 1997 to 1998. From 1989 to 1993 he owned and managed a restaurant in Greenfield, Iowa, and he was State Director of the Iowa Farm Unity Coalition during the Farm Crisis of the 1980s.

Commissioner Norris graduated with distinction from the College of Law at the University of Iowa in 1995 and earned his undergraduate degree in 1981 from Simpson College in Indianola, Iowa.

Commissioner Norris, his wife, Jackie, and their three sons live in Washington, D.C.
Marjorie Rosenbluth Philips (Marji) is the ISO Services Director for Hess Corporation. In that capacity she assists Hess in developing its two generation facilities that will sell power into PJM and the NYISO markets, represents Hess in the various eastern RTOs, and crafts responses to federal and state regulatory and legislative initiatives impacting wholesale electric markets. She has participated in numerous energy forums, including those sponsored by the Federal Energy Regulatory Commission, the New Jersey Board of Public Utilities, Pennsylvania Public Utility Commission, the Maryland State House of Representatives, the Mid-Atlantic Commission of Regulatory Utility Commissioners, Electricity Consumers Resource Counsel, the California Public Utilities Commission, and Platts. Ms. Philips previously worked for PSEG Energy Resources & Trade, LLC, Constellation Commodities Group, and Williams Energy. Prior to moving from the legal to the business side, she practiced law with PECO Energy Company – Power Team, which became part of the Exelon companies, LG&E Power Inc., Skadden, Arps, Slate, Meagher & Flom, and Morgan Lewis, advising clients on transactional and federal and state regulatory matters related to wholesale power markets and independent power projects. She has an undergraduate degree from McGill University, a Masters in International Affairs from Columbia University, and a law degree from Fordham University School of Law. She is a past President of the Northeast Chapter of the Energy Bar Association and currently is a Board member of the Energy Bar Association. She also served as a member of the NERC stakeholder board. Ms. Philips is on the Board of Trustees of the Chamber Orchestra of Philadelphia, and Congregation Rodeph Shalom. Her other full time job is mother to two young adults.
Biography of Lori A. Spence

Lori A. Spence is the Deputy General Counsel and Tariff/FERC Compliance Officer of MISO, a regional transmission organization in eleven Midwest states and one Canadian province. She is responsible for management of the Legal Department, records and information management, tariff and FERC compliance, and regulatory filings.

Ms. Spence is also active in corporate training initiatives involving the Company’s Tariff and Rate Schedules, Standards of Conduct, Code of Business Ethics, antitrust matters, and other corporate policies. She also recently served as a liaison for the Board of Directors’ Corporate Governance & Strategic Planning Committee. Ms. Spence serves on numerous internal Company committees that assess enterprise, legal and regulatory risk, review budgets and forecasts, provide compliance strategies, and look for operational efficiencies to promote the Company’s value proposition and cornerstones.

Prior to joining MISO, Ms. Spence was Senior Counsel for Cinergy Corp. (now Duke Indiana), focusing on federal energy matters for both the transmission and energy marketing business units. She earlier served as Counsel for Cinergy handling litigation and other corporate matters.

Ms. Spence received her Bachelor of Science degree in Public Affairs from Indiana University in Bloomington, Indiana and her JD from Indiana University School of Law in Indianapolis, Indiana. She also completed the Kellogg School of Management Senior Leadership Series for Executive Women at Northwestern University in Evanston, Illinois and is a Certified Compliance & Ethics Professional through the Society of Corporate Compliance and Ethics.
Heather Hendrix Starnes

Heather has been employed with Southwest Power Pool (‘‘SPP’’) since February of 2006, first serving as the Senior Regulatory Attorney. Since January of 2009, Heather has served as Manager of Regulatory Policy. Her duties include primary responsibility for the continued maintenance, development, and all appropriate regulatory approvals of the SPP Open Access Transmission Tariff and related governing documents; oversight of operational and policy decisions related to the Tariff, oversight and facilitation of FERC and state regulatory and relationships, including issues, proceedings, and associated agreements.

Heather received a Bachelor of Arts degree in Business and Accounting from Hendrix College in 1991 and a Juris Doctor degree from the William H. Bowen School of Law in 1993. She is licensed to practice law in Arkansas and Missouri.

Prior to her entrance into the electric industry through Southwest Power Pool, Heather’s legal experience was focused in the areas of municipal, legislative and administrative law.
Steve Sunderhauf currently serves as the Manager of Program Design and Evaluation at Pepco Holdings, Inc. (PHI), the holding company for Atlantic City Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company.

Mr. Sunderhauf is responsible for the design and evaluation of customer demand side management programs for PHI’s three regulated utilities. His responsibilities include the design, development, and evaluation of new smart grid enabled customer product offerings, which include Advanced Metering Infrastructure (AMI) enabled dynamic pricing and AMI enabled demand response equipment.

Mr. Sunderhauf earned an economics degree from Bucknell University, an M.S. degree in public policy and management from Carnegie-Mellon University, and a J.D. from the George Washington University. He is a member of the Maryland Bar.
RICHARD D. TABORS
Vice President

Richard D. Tabors, Vice President, is an economist and scientist with 35 years of domestic and international experience in energy markets, planning and pricing. He is a member of the group at MIT that developed the theory of spot pricing upon which locational marginal pricing (LMP) of electricity and transmission rights markets (such as FTRs) are based. Dr. Tabors continues to work on the restructuring of the U.S. and international electric supply industry, where he provides expert testimony and works with clients on restructuring efforts at the state, provincial, regional, and federal levels in the United States and Canada, as well as in the United Kingdom. His current work is focused on the development of the North America natural gas market with specific focus on the price impacts of natural gas on the structure of the power market and on coordination of the two markets.

Dr. Tabors has extensive regulatory and litigation experience where he has worked on valuation and damages litigation related to federal and state regulation, bankruptcy and contract disputes in both the United States and Canada. His focus has been upon development and defense of client perspective and expectation at the point in time at dispute in the litigation.

Dr. Tabors spent 30 years on the faculty and research staff of MIT where until 2006 he was a senior lecturer in technology and policy and Assistant Director of the Laboratory for Electromagnetic and Electronic Systems (MIT’s Power Systems group) Though a scientist and economist by training, Dr. Tabors has worked and taught throughout his career at the interface between engineering, economics and public policy. He is author of nearly 100 refereed articles and books.
Glen R. Thomas

Glen Thomas is president of GT Power Group. Mr. Thomas is the former chairman of the Pennsylvania Utility Commission (PUC), where he oversaw the restructuring of Pennsylvania’s electricity, natural gas and local telephone markets. Before his appointment to the PUC, Mr. Thomas served as deputy director of Gov. Tom Ridge’s Policy Office, where he advised the governor on energy and environmental issues. In addition, Mr. Thomas was appointed by California Gov. Arnold Schwarzenegger to serve on the governor’s transition team for energy related issues in 2003. Mr. Thomas is also a former partner at the law firm of Blank Rome.

Mr. Thomas has served as president of the Mid-Atlantic Association of Regulatory Utilities Commissioners and chairman of the National Association of Regulatory Utility Commissioners Washington Action Committee. He also served as a member of the U.S. Department of Energy's Electricity Advisory Board; the National Regulatory Research Institute's Board of Directors; the Keystone Center Energy Board; the Organization of MISO States Board of Directors; and the National Association of Regulatory Utility Commissioners Committee on International Relations, Telecommunications and Critical Infrastructure.

Mr. Thomas received his law degree from Dickinson School of Law and his bachelor’s degree in philosophy/religion and political science from Colgate University. He attended the Governors Center of the Terry Sanford Institute of Public Policy at Duke University; the John F. Kennedy School of Government; the Program for Senior Executives in State and Local Government at Harvard University; and was one of the 60 civilians chosen by the Secretary of Defense to participate in the U.S. Department of Defense Joint Civilian Orientation Conference.

Mr. Thomas has been honored by the Philadelphia Business Journal and the Central Pennsylvania Business Journal as recipient of the “40 Under 40” Award. He is also a member of the Wilson High School (Pa.) Academic Hall of Fame.

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Grace C. Wung
Assistant General Counsel
NV Energy

Ms. Wung joined NV Energy in late 2009 and serves as the Company’s in-house Federal Energy Regulatory Commission (“FERC”) counsel. Prior to joining NV Energy, Ms. Wung worked in private practice representing wholesale and retail electricity customers in both ISO/RTO and non-ISO/RTO jurisdictions on various matters including state utility rate and legislative proceedings, demand response, energy efficiency, and FERC jurisdictional rate proceedings. Ms. Wung also counseled clients, including vertically integrated utilities, ISOs, and power marketers on FERC jurisdictional matters involving generator interconnections, transmission service requests, market trading rules in ISO/RTO markets, and other general FERC matters. Prior to working in private practice, Ms. Wung served as a law clerk in the Office of Administrative Law Judges and interned in the Solicitor’s Office at the FERC.

Ms. Wung received her Bachelor of Arts and Sciences from the University of Massachusetts, Amherst, and Juris Doctor from American University, Washington College of Law. Ms. Wung is a member of the Maryland, Massachusetts, New York, District of Columbia, and Nevada Bars.