Shale Gas, Environmental Regulations, Portfolio Diversity and Aging Infrastructure: How to Manage Change in the Northeast Markets

With the abundance of shale gas driving natural gas prices to decade-low levels, environmental regulations that are sending generators into early retirement, and Northeast ISOs and RTOs mapping out compliance strategies for FERC’s Order 1,000, the Northeast Chapter’s Annual Meeting will examine how the industry is managing the ever-changing industry landscape. An impressive collection of industry experts will address issues that include the coordination of gas and electricity markets, transmission planning and cost allocation under new federal rules, and whether capacity markets are working as designed to meet the challenges faced by the region. The Northeast Chapter is also fortunate to host Pennsylvania DEP Secretary Michael Krancer, who will deliver the keynote address, and FERC Commissioner Philip Moeller, who will be speaking during our luncheon program.

PROGRAM SCHEDULE

**WEDNESDAY, JUNE 6, 2012**

<table>
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<tr>
<th>Time</th>
<th>Event</th>
<th>Panelists</th>
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<tr>
<td>8:00 a.m.</td>
<td>REGISTRATION</td>
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<td>8:30 a.m.</td>
<td>WELCOME AND INTRODUCTION</td>
<td>William D. Hewitt</td>
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<td>8:45 - 9:30 a.m.</td>
<td>KEYNOTE SPEAKER</td>
<td>Michael Krancer</td>
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<td>Pennsylvania Department of Environmental Protection</td>
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<td>9:30 a.m.</td>
<td>Gas and Electricity: Is it Time For Market Coordination?</td>
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<td>10:45 - 11:00 a.m.</td>
<td>Transmission Planning in the Northeast After Order 1,000.</td>
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<td>11:15 - 12:15 p.m.</td>
<td>Break</td>
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<tr>
<td>11:00 - 12:15 p.m.</td>
<td>Transmission Planning in the Northeast After Order 1,000.</td>
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As electricity generation increasingly relies upon natural gas, policy makers are considering whether, how and to what extent there should be coordination between the electricity and natural gas markets. This panel will offer a cross section of perspectives on these emerging issues.

Moderator: Richard Miller
Con Edison

Panelists: Kevin Kirby
Vice President, Market Operations
ISO New England

Andrew K. Soto
Sr. Managing Counsel, Federal Regulatory Affairs
American Gas Association

Sarah G. Novosel
Senior Vice President & Managing Counsel
Calpine Corporation

Frank Koza
Executive Director, Operations Support
PJM Interconnection

Dorothy Capra
Director of Regulatory Services
New England States Committee on Electricity

James Gallagher
Sr. Manager for Strategic Planning
New York ISO

10:45 - 11:00 a.m.

**BREAK**

11:00 - 12:15 p.m.

FERC issued Order 1,000 last summer after a year-long docket that comprehensively analyzed and considered transmission planning and cost allocation issues. This panel will examine planning beyond reliability needs, the rights of first refusal and impacts on the market.

Moderator: William D. Hewitt
Pierce Atwood LLP

Panelists: Steve Naumann
Vice President
Exelon Corporation
Thomas Welch
Chairman
Maine Public Utilities Commission

David A. Whiteley
Principal Member
Whiteley BPS Planning Ventures LLC

Steven R. Herling
Vice President of Planning
PJM Interconnection

Garry A. Brown
Chairman
New York State Public Service Commission

Anna Cochrane
Deputy Director of the Office of Energy Market Regulation
Federal Energy Regulatory Commission

12:15 -
2:00 p.m.
LUNCH & LUNCHEON SPEAKER
The Honorable Philip D. Moeller
Commissioner
Federal Energy Regulatory Commission

2:00 -
3:15 p.m.
Market Mitigation, Capacity Markets and Market Design: Are They Working As Intended?
The efficacy and enhancement of capacity markets continues to be a primary focus in the Northeast RTOs. This panel will discuss whether there are fair, cost effective and efficient ways to meet reliability needs, with particular focus on the impact of mitigation rules implemented within the past year.

Moderator: Tamara L. Linde
PSEG

Panelists: Dr. Joseph Bowring
President
Monitoring Analytics

Samuel Newell
Principal
The Brattle Group

Jay Morrison
Vice President, Regulatory Issues
National Rural Electric Cooperative Association

3:15 -
3:30 p.m.
BREAK

3:30 -
4:45 p.m.
Generator Retirements: Is the Northeast Prepared?
Capacity markets are supposed to provide ease of generation entry and exit without extreme volatility and RTO-driven out-of-market actions. With increasingly strict environmental rules forcing retirements, this panel will continue the previous discussion on capacity markets and examine how generation retirements are currently being managed, both in terms of maintaining reliability and capacity market efficacy.

Moderator: Marjorie Rosenbluth Philips
Hess Corporation

Panelists: Dean Ellis
Director, Asset Management
Dynegy

Susan N. Kelly
Senior Vice President, Policy Analysis and General Counsel
American Public Power Association

Mark Karl
Sr. Director, Resource Adequacy
ISO-New England

The Honorable Bob Martin
Commissioner
New Jersey Department of Environmental Protection

Morgan E. Parke
FirstEnergy Corp.

4:45 p.m.
Concluding Remarks and Reception

Thank You To Our Sponsors!
Black & Veatch
Blank Rome LLP
Pierce Atwood LLP
U.S. Power Generating Co.
Gas and Electricity: Is it Time for Market Coordination?
In accordance with the Federal Energy Regulatory Commission’s (“Commission” or “FERC”) February 15, 2012 Notice Assigning Docket Nos. and Requesting Comments (“Notice”), ISO New England Inc. (“ISO-NE”) respectfully submits comments in this proceeding. ISO-NE appreciates the opportunity to comment on the important issues raised in this proceeding. Approximately forty percent of New England generators are fueled by natural gas and this number is expected to increase, particularly if existing coal and oil-fired generators retire due to economic and environmental factors. As a non-profit Regional Transmission Organization with the responsibility to protect electric reliability in New England, ISO-NE is committed to developing efficient solutions to address the availability of gas-fired units in New England.

In 2011, ISO-NE and New England stakeholders initiated strategic planning discussions (the “Strategic Planning Initiative”) to identify existing and upcoming challenges to the continued reliable and efficient operation of the bulk power system in New England. The Strategic Planning Initiative identified the increased reliance on natural gas as one of five risks facing New England.¹ As part of the Strategic Planning Initiative, ISO-NE commissioned ICF International to conduct an assessment of the amount of natural gas infrastructure available to

¹ The other risks are resource performance and flexibility; retirement of generators; integration of a greater level of variable resources; and alignment of markets and planning. Information pertaining to the Strategic Planning Initiative can be found at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html
satisfy New England’s gas-fired generation through 2020 (the “ISO-NE 2011 Natural Gas Study”). The initial findings of the ISO-NE 2011 Natural Gas Study show that the region’s gas delivery system is inadequate to fully serve regional power plant demands on a winter design day over the next decade. The potential repowering of oil- and coal-fired resources with new natural gas facilities – or contingencies on the gas delivery system – could lead to even tighter gas delivery capability. The findings of the ISO-NE 2011 Natural Gas Study suggest that improved incentives to assure fuel and resource availability to address regional reliability needs should be examined. Through the Strategic Planning Initiative and other efforts, ISO-NE and New England stakeholders are actively working to develop solutions to the region’s increased dependency on natural gas.

Pursuant to the Notice, ISO-NE provides responses to the following questions.

1. **What role should the Federal Energy Regulatory Commission (“FERC”) have in overseeing better coordination? What duties should be delegated to the North American Electric Reliability Corporation (“NERC”), the North American Energy Standards Board (“NAESB”), or other entities?**

**Response**

As the agency with jurisdiction over both interstate natural gas pipelines and the wholesale sale of electricity, the Commission has an important role in ensuring that both industries develop solutions that address coordination issues in a timely and just and reasonable manner. Through Order Nos. 698, the Commission has already taken steps to improve communications between interstate pipelines and electric utilities, and ISO-NE has implemented business practices to improve communications and foster information-sharing relationships with the gas industry in the Northeast. For example, on September 27, 2007, the Electric/Gas

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Operations Committee ("EGOC") approved the "Electric/Gas Operations Protocol," which supports the Commission’s communication efforts in Order Nos. 698. The EGOC, which is co-chaired by ISO-NE and the Northeast Gas Association ("NEGA"), includes over 50 members with representatives from the ISO, the New York ISO, PJM, NERC, NPCC and regional interstate gas pipelines, LDCs and LNG facilities.

The EGOC communications protocol identifies the mechanism to be used should the ISO need the assistance of any regional natural gas company to help mitigate electric power operating emergencies and/or other abnormal conditions jeopardizing the reliability of New England’s power system. The protocol also addresses situations where natural gas entities may need assistance from ISO-NE. The protocol defines the regular flow of information, real-time communications, communications between ISO-NE and NEGA and regional gas companies, and industry contact and coordination during non-business hours. In addition, ISO-NE receives automatic messages from the regional pipelines’ Electronic Bulletin Boards concerning Critical and Non Critical Notices.

Coordination and communication of maintenance outages between the two industries is important for the reliability of both sectors. Among ISO-NE’s responsibilities is the scheduling and coordination of transmission equipment outages on the bulk power system. Outages on the electric transmission system can have a substantial impact on gas flow and pressure on interstate pipelines. Similarly, given the tight gas supply in New England, the outage of an interstate pipeline could cause reliability problems in ISO-NE’s control area. The frequency and duration of inspection and maintenance outages on interstate pipelines is expected to increase due to the recently enacted Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. ISO-NE is
currently working with the gas industry to better understand and coordinate outages on each others’ systems.

ISO-NE recognizes that communications alone will not resolve all reliability issues associated with the region’s dependence on natural gas. Through the Strategic Planning Initiative, ISO-NE and the New England stakeholders are in the initial stages of identifying enhancements to existing wholesale electricity markets, the development of new products and other solutions that will incentivize resources to take actions to ensure sufficient fuel availability to meet their obligations. Many, if not all, of these solutions, will require changes to ISO-NE’s existing market rules and will be filed with the Commission for review and approval.

While the Commission has an important role in ensuring that efficient solutions are developed in a timely manner, neither the Commission, NERC nor NAESB should impose a “one-size-fits-all” national standard such as requiring all gas generators to have firm transportation using traditional pipeline rateable off-take terms or dual fuel capability. Given the different resource mix and fuel availability, each region should be allowed the flexibility to tailor appropriate solutions to serve daily consumer load profiles and to address fuel supply interruptions and system contingencies in a manner that balances the cost of delivered power while mitigating the possibility of involuntary service interruptions, particularly on coincident peak load days for both industries. The problem in New England is particularly acute during peak winter days or when there is a contingency on the interstate pipeline. As such, some of the appropriate solutions in New England could include increased firm pipeline capacity, dual-fuel generation and/or local fuel storage to serve peak needs.

With respect to natural gas pipelines, it is important that pipeline tariffs provide the most flexibility possible to accommodate the variable needs of gas-fired generators. ISO-NE is
working with the gas industry and other stakeholders to identify pipeline service enhancements such as hourly, no-notice and non-rateable takes so that generators can meet the net hourly load following and contingency responses needed for reliable electric operations. Construction of new pipeline infrastructure is expensive, especially if it is only fully utilized a limited number of days a year. There may be opportunities to accommodate some of the demands of the electric sector through new services offered through existing pipeline facilities.

2. To what extent should FERC defer to various regions of the country in addressing these challenges? Should FERC view organized electricity markets differently from bilateral electricity markets? If regional differences are given, what role should FERC play to assure that regional agreements are adhered to?

Response

Because different regional electric systems have their own characteristics and priorities, many of the challenges in each region are likely to be unique and the Commission should allow each region to develop appropriate solutions. FERC can play an important role by facilitating a discussion of the gas-electric coordination issues at the national level. Indeed, a discussion of gas-electric coordination issues at the national level could help inform the development of regional solutions.

With respect to organized electricity markets, ISO-NE believes that, when possible, utilizing the competitive markets to address reliability problems will produce efficient solution(s). As discussed above, ISO-NE and the New England stakeholders are in the initial stages of developing solutions to reliability issues due to New England’s reliance on gas-fired generators. These solutions will be tailored to address the unique circumstances in New England. As such, ISO-NE requests that the Commission defer to solutions developed by ISO-NE working through
the New England stakeholder process and allow New England to develop appropriate and efficient market solutions that address the unique challenges facing the region.

3. The expanded use of natural gas for electricity generation is likely to change flows on the natural gas pipeline system. Does FERC need to address this issue?

Response

The expanded use of gas-fired generation and the emergence of shale gas are already causing changes in gas flows in New England. In order to get a better understanding of the impact of gas flows on a regional and national level, ISO-NE suggests the Commission convene a technical conference to discuss this issue. Such a conference should include representatives from ISOs, electric generators, interstate pipelines, local gas distribution companies and customers so that the breadth of perspectives on these changes can be discussed.

4. Within each day, electricity trading differs significantly from gas trading. Similarly, on a day-to-day basis, the various gas markets may not be open on the same days as the corresponding electricity markets, especially over Saturdays, Sundays, and Holidays. How should FERC help to harmonize these markets?

Response

The differences in the natural gas and electric operating days may make it difficult for gas-fired generators to satisfy the scheduling requirements in both industries. In New England, this issue is particularly acute during cold weather conditions or during contingencies on the interstate pipeline grid, where there is limited capacity to serve non-firm customers. ISO-NE is working with pipeline companies and other stakeholders to consider changes to the scheduling requirements within its electricity markets to provide better alignment with the gas nomination and electric scheduling cycles. For instance, ISO-NE is considering allowing hourly offers into
the ISO-NE Day-Ahead Market, allowing resources to re-offer in the real-time energy market, and making adjustments to the timing of the Day-Ahead Market.

5. **What will be the impact of the expected retirements of coal and oil-fired generation on the need for gas and electric coordination?**

   **Response**

   It is anticipated that retirements of coal- and oil-fired generation will increase New England’s dependency on natural gas, as the region loses capacity that provides fuel diversity and it is replaced primarily with gas-fired resources. In this regard, it is notable that while New England’s older, fossil-fired generation operates at very low, annual capacity factors, those resources provided over 20% of the region’s energy on the peak day in 2011. As such, the retirement of coal- and oil-fired generation will increase the need for greater gas and electric coordination, in addition to the aforementioned market and scheduling enhancements and infrastructure needs. The retirement of certain fossil fuel generators in New England is another risk identified under the Strategic Planning Initiative and is directly related to the region’s increasing dependency on natural gas. Through the strategic planning efforts, ISO-NE is evaluating both market products and strengthened incentives to assure that resources can deliver the services needed as the make-up of the region’s generation fleet changes.

6. **To what extent should FERC consider modifying its existing Standards of Conduct with regulated utilities—either on an emergency basis or in a more fundamental manner—to assure greater coordination of these industries?**

   **Response**

   It is ISO-NE’s understanding that some RTOs have experienced difficulty obtaining certain information from the interstate pipelines due to the standards of conduct. While ISO-NE has not had similar problems, ISO-NE believes the Commission should convene a technical
conference to explore whether the standards of conduct have, or are likely to have, an impact on legitimate reliability-related communications between the gas and electric industries.

7. Will progress on this issue be faster if policies are addressed in several “baskets”, such as communication, operation, contracting and planning/contingency analysis? If so, what are the appropriate “baskets”?

Response

ISO-NE believes it is appropriate to address the issues in different “baskets” such as communications/code of conduct, scheduling/market issues, and potential new services/products offered by the pipelines. Some issues, such as communications, can probably be addressed quickly. As discussed above, ISO-NE and the interstate pipelines in New England have already taken a number of steps to ensure effective communications between the two sectors.

Other issues, such as market enhancements, are more complex and will take time to develop and implement, and should be developed regionally so that the changes are tailored to address the unique circumstances in each region. As these solutions are developed, FERC will play an important role in overseeing any national consequences of regional actions and assuring that a reliable, just and reasonable energy infrastructure continues to develop nationally. With its national perspective and regulatory oversight authority over both gas and electric issues, FERC is uniquely positioned to fill this important oversight function.
We look forward to working with New England stakeholders, the region’s regulators, the gas industry, other ISOs and RTOs, and FERC as we address these important issues.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: /s/ Raymond W. Hepper

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Dated: March 30, 2012
CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the parties designated on the official service list for the above-captioned docket in accordance with the requirements of Rule 2010 of the Commission’s Rules of Practice and Procedure. 18 C.F.R. § 385.2010 (2011).

Dated at Holyoke, Massachusetts on this the 30th day of March, 2012.

/s/ E-filed ___________________________
Coordination between Natural Gas and Electricity Markets) Docket No. AD12-12-000

COMMENTS OF THE
AMERICAN GAS ASSOCIATION

Pursuant to the notice issued in this docket on February 15, 2012, by the Federal Energy Regulatory Commission (“Commission”), the American Gas Association (“AGA”) respectfully submits these comments. At the outset, AGA notes that America’s natural gas resource base is immense with large, economically accessible natural gas resources that include significant sources of unconventional gas such as shale gas. According to analysts, current natural gas reserves have the ability to supply over 100 years of demand at today’s consumption rates. The United States has conventional and unconventional production from North American locations, and gas storage capacity in nearly all major supply and market areas. Onshore shale gas located in more than 20 states greatly reduces exposure to the disruptive effects that hurricanes have had on off-shore supplies and spot market prices. In addition, the U.S. pipeline and storage network is highly reliable. Production can be accessed from virtually all major North American gas-producing regions and delivered via a highly integrated pipeline transportation network across the United States using many different transportation paths. While unusually severe weather events have the potential to disrupt the natural gas system, outages of firm pipeline transportation and storage services have been rare. In sum, the natural gas production, transmission, storage and distribution systems in this country support the most flexible and resilient natural gas market in the world.
In considering the broad issues of how to achieve greater coordination between the natural gas and electricity markets, AGA believes that the Commission should be guided by the following principles:

- The overall goal of gas-electric coordination efforts should be to preserve and, where appropriate, enhance reliability for all customers, both gas and electric.
- Gas and electric stakeholders must collaborate to meet this overall objective.
- Policymakers and industry leaders should initiate a dialogue that addresses the reliability of both the gas and electric systems in a coordinated manner, not one at the expense of the other. In that regard, the Commission should have a bias toward enabling creative market solutions to enhance coordination between the natural gas and electricity markets, and not merely establish additional regulatory requirements.
- The Commission should establish a clear policy framework that reflects variations in reliability issues at the regional level in terms of infrastructure, scope and timing. Priority should be given to those regions where the need is most urgent. The Commission must provide policy guidance in advance of others moving to implement specific solutions.
- The Commission should recognize ongoing regional efforts to address reliability issues, draw on stakeholders’ existing knowledge of regional operations and promote continued collaboration among all stakeholders on a regional basis; and
- The industries’ immediate concerns include improving local communication and coordination among gas utilities, pipelines, electric utilities, power generators, regional electric transmission system operators (where they exist), and other
electric transmission operators to ensure reliability during periods of peak
demand, system constraints or supply or transportation disruptions on the gas
systems.

Based on these principles, AGA recommends, among other things, that the Commission
take a leadership role in quickly convening a series of technical conferences at both the national
and regional levels that clearly identify and organize general policy goals and objectives and also
address specific regional concerns. Regional technical conferences should address ways in
which the natural gas and electric industries can work together to develop appropriate
coordination mechanisms and communication protocols that would ensure the safety and
reliability of both systems during severe weather or outage events. AGA believes that the
Commission can provide great value by guiding continued collaboration among all stakeholders
on a regional basis.

I. COMMUNICATIONS

All pleadings, correspondence and other communications filed in this proceeding should
be served on the following:

Andrew K. Soto    Arushi Sharma
American Gas Association American Gas Association
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Washington, DC 20001 Washington, DC 20001
(202) 824-7215 (202) 824-7120
asoto@aga.org asharma@aga.org

II. IDENTITY AND INTERESTS

The AGA, founded in 1918, represents more than 200 local energy companies that
derive clean natural gas throughout the United States. There are more than 71 million
residential, commercial and industrial natural gas customers in the U.S., of which 92 percent —
more than 65 million customers — receive their gas from AGA members. AGA is an advocate
for local natural gas utility companies and provides a broad range of programs and services for
member natural gas pipelines, marketers, gatherers, international gas companies and industry
associates.¹

AGA member local distribution companies ("LDCs") take service from virtually every
interstate natural gas pipeline regulated by the Commission under the Natural Gas Act. As
customers of jurisdictional pipelines, AGA members are directly affected by the rates, terms and
conditions of the transportation and storage services provided by jurisdictional pipelines and
storage providers, including rules affecting the reliability of the natural gas system and the
coordination between the natural gas and electricity markets. AGA’s members, therefore, have a
direct and substantial interest in the issues raised in this proceeding.

III. COMMENTS

A. Background

On February 15, 2012, the Commission initiated this proceeding to receive industry input
on the important issues related to coordination between the natural gas and electricity markets.
Commissioner Moeller had previously issued on February 3, 2012, a request for comments on
coordination between the natural gas and electricity markets. The request noted that these
industries provide services critical to the health and safety of the nation and expressed the desire
that outages and adverse reliability impacts not result from a lack of coordination between the
electricity and gas industries. The request stated that while comprehensive solutions may take
longer to implement, actual improvements must be made now. The request sought responses to
several specific questions regarding the roles that the Commission, the North American Electric
Reliability Corporation ("NERC") and the North American Energy Standards Board ("NAESB")

¹ For more information, please visit www.aga.org.
should play, the deference the Commission should show to regional variation, the impact of changing gas flows on the pipeline system, the differences in how wholesale gas and wholesale electricity is traded and scheduled, the impact of retirements of coal-fired and oil-fired electric generating units, and whether modifications to the Commission’s standards of conduct may assure greater coordination.

Commissioner LaFleur, in a statement given at the February 16, 2012 Commission Open Meeting also noted that the electric industry’s increased reliance on natural gas has greatly heightened the need to address how the gas and electric markets and operating networks can better work together. Commissioner LaFleur highlighted five aspects of gas-electric interdependence on which she sought comments, including: (1) coordination and communication to maintain reliability during outage events; (2) new pipeline and storage service and pricing structures that might better meet the needs of generators; (3) scheduling protocols; (4) electric reliability standards; and (5) pipeline and storage infrastructure.

AGA appreciates the leadership the Commissioners have shown to address the importance of ensuring the reliability of both the gas and electric systems for all customers. AGA offers the following comments with regard to these issues in general and in response to the specific questions posed by the Commissioners.

B. AGA Principles on Gas-Electric Interdependencies

Fundamentally, AGA believes that the focus of the Commission’s consideration of these issues should be on reliability. Any efforts to achieve greater coordination or integration of the natural gas and electricity markets should have as their goal the preservation and, as necessary, the enhancement of the reliability of both systems for the benefit of all customers, both gas and electric. Greater coordination and integration of the systems will require both gas and electric
stakeholder groups to collaborate on ways to maintain the reliability of each system. Many of
these collaborative efforts are underway; however, AGA remains concerned that the interests of
both gas and electric customers are not adequately represented in all of the collaborative efforts.
AGA believes that the Commission should bring policy makers and industry leaders together to
continue a dialogue that addresses the reliability of both the gas and electric systems in a
coordinated manner. AGA requests that the Commission provide the framework in which such a
dialogue can take place. In that regard, AGA encourages the Commission to show a bias
towards enabling creative market solutions to enhance coordination between the natural gas and
electricity markets, and not merely establish additional regulatory requirements.

Moreover, efforts to address the reliability of an electric system increasingly dependent
on natural gas supply should not result in a deterioration of the quality of service to, or in the
imposition of additional cost burdens on, natural gas producers or customers. The reliability of
one system should not be achieved through subsidization by the other system’s customers. Nor
should such efforts impose costs on the other system’s customers if they provide no reliability
value to such customers. AGA therefore urges the Commission to carefully examine how
particular reliability efforts will affect both gas and electric customers.

AGA also believes that the Commission’s efforts to increase the coordination between
the gas and electric industries should reflect variations in reliability issues at the regional level.
Such variations may be driven by infrastructure needs, market conditions, state or regional
regulatory requirements, or other factors. In that regard, the Commission should prioritize its
coordination efforts in the regions in which reliability concerns are most urgent. In addition, the
Commission should look to regional stakeholders’ existing knowledge of their operations,
conditions and issues and promote continued collaboration among all stakeholders on a regional
basis. The Commission, with the participation of appropriate natural gas industry stakeholders, should encourage each region to examine its existing electric planning processes to consider whether there is an over-reliance on interruptible gas transportation service to meet electric reliability needs.

AGA agrees that steps can and should be taken in the near term to ensure the continued reliability of both the gas and electric systems for all customers, while more comprehensive solutions are developed and implemented to address how closer coordination between the two markets will ensure the reliability of both systems in the longer term. AGA believes that immediate concerns include further improving local communication and coordination during periods of peak demand on the gas system, including better understanding of the actions taken by system operators on both systems, particularly when system constraints or supply or transportation disruptions on the gas system pose reliability concerns for all gas customers. Operators of gas utilities, gas pipelines, electric utilities, power generators, regional electric transmission system operators (“RTO’s”) and independent system operators (“ISOs”) where they exist, and other electric transmission operators must all work together within the constraints of their respective regulatory regimes to ensure the reliability of both the gas and electric systems.

With these principles in mind, AGA offers the following responses to the individual questions posed by the Commissioners.

C. Responses to Commissioner LaFleur’s Questions.

1. What are the issues with regard to coordination and communication between the gas and electric industry to maintain reliability during weather or outage events?

AGA believes that the Commission’s overall goal should be to preserve and, where appropriate, enhance reliability for all customers – both gas and electric. To this end, several
coordination and communication issues may arise when considering the reliability of both the

gas and electric systems during severe weather or outage events. Gas-fired generators that have

only contracted for interruptible transportation service on pipelines may find that interruptible
capacity is unavailable during severe weather or outage events, because the capacity is being

used by firm service customers. Even when capacity is available, the gas system can experience

significant pressure drops due to generators drawing large quantities of gas that were not

scheduled, potentially causing problems for all gas customers on the system. In addition, gas

pipeline compression facilities can be adversely affected by electric outages, further reducing the

amount of gas available to supply electric generators and other pipeline customers.

Addressing reliability will require a better understanding of both day-to-day and longer-
term impacts on operations, planning and costs to consumers. AGA urges the Commission to

identify issues on a regional basis, keeping in mind that reliability is a function of regionally-
specific operating conditions. Regional factors that may impact reliability during severe weather

or outage events may include the following:

(i) interstate and intrastate pipeline and storage capacity relative to demand;

(ii) the availability and capabilities of gas-fired generation capacity (e.g., the extent to

which they rely on firm or interruptible pipeline transportation services or may have the ability to

switch to alternative fuels);

(iii) the level of access to alternative gas supply sources, gas supply diversity, and the

degree to which pipeline customers are dependent on a specific pipeline or supply region;
(iv) the extent to which existing state regulations and/or local requirements (such as electric market rules that require alternate fuel capability for gas-fired generators)\(^2\) provide a foundation for reliability and coordination between the gas and electric systems;

(v) the scope of current gas products, services and contracting practices offered by interstate and intrastate pipelines, storage operators, and LDCs, including the historical usage patterns and expectations, and scheduling and nomination protocols;

(vi) the nature of gas demand growth, including changing demand characteristics due to integration of renewable generation resources and demand response;

(vii) the extent to which gas transmission and distribution facilities are dependent upon electricity for their operations; and

(viii) the level of coordination between gas and electric stakeholders and the nature of current regulatory requirements involving gas-electric coordination.

In order to improve coordination or communication in the short-term, gas and electric stakeholders need to learn from each other on a regional and local basis. Coordination mechanisms include the operational steps that natural gas and electric systems can take in emergency or near-emergency situations to protect the reliability of each system. For example, electric transmission operators can redispacth their systems or order dual-fuel generators to switch fuels when pipeline capacity is unavailable to serve interruptible loads. In that regard, electric transmission operators should fully understand the significance of the information they receive from pipelines and develop operating procedures to address pipeline capacity

\(^2\) For example, gas-fired generators in New York City are generally required to have dual-fuel capability, maintain specified levels of back-up fuel, and to have automatic fuel switching capability or operate on alternate fuel during critical system conditions. The fixed costs of dual-fuel capability are reflected in the capacity market demand curves for New York City.
unavailability. Likewise, they should understand the implications of power failures on pipeline compression facilities and LDC operations.

AGA urges the Commission to take a leadership role in convening regional conferences to ensure that effective communication is taking place among all the relevant regional stakeholders. In that regard, regional communication efforts should ensure that gas system interests are adequately represented and should include alternative energy providers and state regulators as well. Accordingly, AGA recommends that the Commission hold a series of regional technical conferences to discuss ways in which the natural gas and electric industries can work together to develop appropriate coordination mechanisms and communication protocols that would ensure the safety and reliability of both systems during normal operations as well as during severe weather or outage events.

2. *What are new pipeline and storage services and pricing structures that might better meet the emerging needs of generators?*

AGA encourages the Commission to continue to be open to creative market solutions to meet the needs of gas-fired generators in ways that do not adversely affect existing shippers. AGA requests that the Commission’s discussion of emerging generator needs and new services to accommodate these needs also address how those needs affect the historical quality of service received by all pipeline customers, including gas LDCs. The Commission should ensure that any initiatives addressing the reliability of the natural gas pipeline systems and the interdependency of the gas-electric systems must have as an overriding goal the preservation of the historical quality of service received by all pipeline customers, including LDCs, industrials, electric generators, marketers, and asset managers. These discussions should also recognize that
pipelines are currently designed to provide existing pipeline customers the reliability that such customers need.

In addition, AGA urges the Commission to consider to what extent innovative services that gas systems have already created accommodate the needs of power generators to access gas supplies in a timely manner in response to electric dispatch orders. Many of these existing services cater to large swings in gas consumption as a result of gas-fired generation being dispatched in response to variable energy resources such as solar and wind cycling on and off, which presents significant challenges to natural gas transmission and distribution systems. Indeed, in some cases LDC distribution service may meet the needs of gas-fired generators in managing large swings in consumption. While not endorsing any particular service offering as the solution for meeting the needs of the electric generation market, these services provide examples of how individual pipelines are creating and developing services to meet the particular needs of the markets they serve. Further, AGA believes that the Commission should not limit its consideration to new structures for pipeline and storage services alone, but should include consideration of the cost impacts on consumers, including electric market cost recovery mechanisms that can be employed to facilitate gas transportation and storage capacity purchases by gas-fired generators, dual fuel capability and/or fuel diversity.

AGA does not believe that the problem is technically insurmountable. As noted, gas services can be designed to reliably serve the needs of gas-fired generators. These services,

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3 See e.g., Texas Gas Transmission, LLC, 130 FERC ¶ 61,158 (2010) (accepting tariff proposal to establish, on a two-year experimental basis, a new Winter No-Notice Service to meet the needs of the electric generation market); Natural Gas Pipeline Co. of Amer., 92 FERC ¶ 61,221 (2000) (accepting tariff sheets to establish a new Firm Reverse Storage Service designed primarily to meet the needs of the electric generation market during the summer peak period); ANR Pipeline Co., 89 FERC ¶ 61,210 (1999) (accepting proposal to create a firm and interruptible hourly flow service designed to meet the demand for natural gas among electric generators and those who service the electric generation market).
however, must be aligned with the market incentives for generators to enter into contracts for those services, when needed, without the creation of cross-subsidies.

3. **What are the issues to address regarding scheduling protocols for gas pipelines and electric generation facilities?**

Examining changes to the gas nomination schedule in order to better coordinate with the electric nomination cycles is not a new idea. Indeed, this ground has been plowed very recently without success. One need only go back to the Commission’s July 2009 notice of proposed rulemaking\(^4\) leading to Order No. 587-U\(^5\) for a discussion of the result. As the Commission described there, Order No. 698\(^6\) directed NAESB to consider whether changes to the existing intra-day schedules would benefit all shippers and provide better coordination between gas and electric scheduling.\(^7\) None of the proposals examined by the NAESB subcommittee assigned to the task achieved consensus, and comments to the NAESB Executive Committee on the issue were mixed as to whether any of the proposals were practical, cost-effective, or feasible.\(^8\) In particular, the Commission noted that some commenters believed that changing the gas nomination schedule would accomplish little for gas electric coordination without a coordinated development of a standardized electric schedule.\(^9\)

The Commission ultimately agreed with local distribution companies “that ‘a simple, one-size fits-all solution does not exist that will solve the complex issue of coordinating between


\(^{7}\) July 2009 NOPR at P 15.

\(^{8}\) *Id.* at PP 18-19.

\(^{9}\) *Id.* at P 19.
the electric and gas industries, [because] the diversity within the electric industry (e.g., differing timelines, system peak times, generation mixes, and prevalence of firm gas service), in particular, does not suggest that revising gas scheduling procedures is the most effective means to improve coordination.”\textsuperscript{10} The Commission concluded that rather than making a nation-wide change in scheduling affecting all pipelines, the issue is best addressed by individual pipelines adding additional nomination opportunities or services to better accommodate specific conditions on their systems to meet the needs of gas-fired generators within their regions.\textsuperscript{11} Such changes could be complemented by changes in regional electric scheduling procedures.

AGA continues to agree with the Commission’s approach to let individual pipelines develop services that would meet the needs of the customers on their systems. Little has changed in the scheduling and nomination procedures for arranging wholesale natural gas and electric services to suggest that a new NAESB-led effort to examine the gas nomination schedule would be any more successful than the most recent effort described above. Indeed, AGA continues to believe that the present diversity in electric scheduling practices makes it difficult to achieve a coordinated energy day. Further, it is not clear that a uniform energy day or scheduling procedures can be developed that will satisfy the electric industry nationwide.

For these reasons, AGA urges the Commission not to focus narrowly on whether changes could be made to the gas nomination and scheduling procedures as a solution for electric reliability concerns. Nonetheless, AGA is willing to keep an open mind and revisit, at the appropriate time, the issue of whether efficiencies can be built into the gas and electric days to achieve greater efficiencies and coordination to protect the reliability of both systems. The Commission, however, should provide policy direction in this area in order for any exploration

\textsuperscript{10} \textit{Id.} at P 21.
\textsuperscript{11} \textit{Id.} at P 22.
of such efficiencies to be successful. Moreover, the Commission should carefully examine how particular reliability efforts will affect both gas and electric customers. Efforts to improve the reliability of an electric system increasingly dependent on natural gas supply should not result in a deterioration of the quality of service to or in the imposition of additional costs on natural gas producers and customers. The reliability of one system should not be achieved through subsidization by the other system’s customers.

4. Regarding electric reliability standards, is there a need to include standards about fuel supply to support reliability?

AGA believes that efforts to maintain and improve the reliability of both the gas and electric systems should include consideration of market solutions that already exist as well as new ones that would provide sufficient incentives for gas-fired generators to purchase the pipeline services they need to accommodate expected operations. The gas industry can then build the infrastructure needed to ensure the reliability of both systems. An important element of that consideration is whether electric market cost recovery mechanisms can be employed to facilitate gas transportation and storage capacity purchases by gas-fired generators, dual-fuel capability and/or fuel diversity. AGA, however, takes no position at this time as to whether electric reliability standards could appropriately be utilized to provide the proper incentives.

5. How can we improve the Commission’s work on pipeline and storage infrastructure to ensure that the gas infrastructure is in place to support the nation’s growing reliance on gas for generation?

AGA believes that the Commission’s program to conduct the environmental review and certification of new natural gas pipeline and storage infrastructure projects has worked very well to allow the marketplace to build the infrastructure necessary to not only reliably meet customer
needs but also to improve the efficiency of natural gas markets. AGA congratulates the Commission and its staff for their tireless efforts to improve the nation’s natural gas infrastructure.

AGA supports the Commission’s efforts to take a close look at current infrastructure certificating policies in order to determine whether improvements can be made to facilitate the reliability of the natural gas system and its interrelationship with the electric system. As a short-term measure, AGA recommends that the Commission review existing certificate applications and expedite review and approval of those projects that are needed to address system reliability, particularly in those regions facing immediate capacity constraints. Adequate recognition should be given to the need for sufficient lead time to place facilities into service to address capacity constraints.

In the longer term, pipeline customers impacted by increased gas demand for power generation should be able to contract for the transportation and storage services that would support construction of the facilities necessary to maintain and enhance system reliability. In these circumstances as well, consideration should be given to when the additional pipeline or storage capacity may be needed to support increased demand from power generators. In regions served by only one or two pipelines, time is of the essence when it comes to adding new capacity to serve both gas and electric customers. In other regions, access to storage may be a key element of gas supply planning. Given these varied conditions, the Commission should evaluate whether its certificating policies provide the correct economic incentives and practical tools needed to bring new assets into service in a time frame consistent with the emerging needs of power generation customers and expectations of continued reliability for existing customers. Accordingly, AGA recommends that the Commission build gas and electric reliability concerns
into a determination of project need, especially where a project requires enough lead time to be built and placed in service to address looming system constraints, or severe weather events or other outages.

**D. Responses to Commissioner Moeller’s Questions**

1. *What role should the Federal Energy Regulatory Commission have in overseeing better coordination? What duties, if any, should be delegated to the North American Electric Reliability Corporation (NERC), the North American Energy Standards Board (NAESB), or other entities?*

The gas and electric industries look to the Commission for policy leadership in the area of gas-electric coordination. AGA believes that the Commission has a unique role in establishing a policy framework for maintaining the reliability of both systems that reflects variations in reliability concerns at the regional level and provides for solutions that are based on real circumstances in particular markets. The Commission should draw on the expertise and understanding of regional infrastructure needs and market conditions developed through existing stakeholder discussions; however, the Commission should provide leadership for these ongoing regional efforts to address reliability issues and ensure that these efforts include all relevant stakeholders. Priority should be given to those regions where the need is most urgent.

Specifically, AGA recommends that the Commission initiate a series of technical conferences to clearly identify and organize general policy goals and objectives and also address specific regional concerns. In the course of these efforts, the Commission should specifically review whether regulatory requirements regarding communication among pipeline operators and transmission system operators can be modified to address the reliability of both systems. AGA
emphasizes that the Commission can provide great value by guiding continued collaboration among all stakeholders on a regional basis.

With respect to the roles that standards-setting organizations such as NERC and NAESB should play, AGA believes that the Commission should provide policy guidance before any such organizations move forward to implement specific technical solutions. AGA appreciates the work of the NAESB Board-level effort on gas-electric harmonization to identify issues requiring greater coordination between the natural gas and electricity markets. Because this NAESB effort has participation from both industries, to the extent its anticipated report summarizes the points raised by others in a balanced fashion, its observations and recommendations could be a useful input for the Commission’s development of a guiding framework.

However, according to NAESB’s own bylaws, its committees, subcommittees and task forces are not permitted to create policy in their standards development activities.12 In the past, NAESB has experienced delays or has been unable to proceed when policy issues arose. Efforts to develop national solutions to address the closer coordination of the gas and electric industries are fraught with policy implications. In addition to the regional concerns noted above, efforts to address reliability for some customers often impose costs on others. Reliability is not free. Cost causation and cost allocation issues require policy calls that NAESB’s working groups cannot make. Accordingly, AGA believes that the Commission should identify the issues and provide necessary policy guidance on potential solutions in advance of directing a standards-setting organization to move forward on implementing a technical solution.

Moreover, to the extent the Commission identifies business practice standards that may be required to implement such solutions and directs NAESB or other standards-setting

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organizations to develop such standards, the Commission should provide sufficient policy
direction to enable the technical working groups to function efficiently. AGA also recommends
that the Commission provide NAESB participants with a quick and efficient means by which
policy disputes, should they arise, can be resolved so that the standards development process can
continue to its completion.

2. To what extent should FERC defer to various regions of the country in addressing
these challenges? Should FERC view organized electricity markets differently from bilateral
electricity markets? If regional deference is given, what role should FERC play to assure that
regional agreements are adhered to?

As noted above, reliability issues vary by region based on infrastructure, market
conditions, regulatory requirements and timing. Infrastructure differences include the type and
mix of electric generating capacity and the extent to which gas-fired generators are able to (and
may be required to) switch to alternate fuels, as well as the natural gas transportation and storage
facilities present in the region. Differences in market conditions include the availability and
diversity of natural gas supply, transportation and storage capacity to meet the demands of all
customers in the region as well as the services and contract offerings by suppliers, pipeline and
storage operators and LDCs in the region. On the electric side, market variations include the
level of fuel diversity in electric generation and, as noted, organized versus bilateral markets and,
in particular, the extent to which market rules (organized or bilateral) provide incentives or
disincentives for gas-fired generators to purchase the pipeline services they need to operate
reliably. Federal, state and local requirements may also result in regional differences that affect
reliability. Regional electric reliability requirements, state initiatives regarding resource
planning, the promotion of renewable resources and the use of gas-fired generation to integrate
intermittent resources, and efforts at coordination among gas and electric stakeholders can all vary region by region. These differences have an effect on the types of solutions available to address the reliability of both the gas and electric systems in a particular region. In addition, the need to address reliability concerns may be more acute in some regions than in others.

As a result of these regional variations, AGA urges the Commission not to take a “one-size-fits-all” approach in addressing reliability concerns or to impose national requirements that do not properly take regional variations into account. With that in mind, however, AGA believes that the Commission is well-positioned to set the stage for appropriate regional discussions. Rather than creating regional policy, the Commission should encourage and guide the various regions to engage in collaborative efforts to resolve their unique challenges.

3. The expanded use of natural gas for electricity generation is likely to change flows on the natural gas pipeline system. Does FERC need to address this issue?

Increased gas demand for power generation has already begun to change flows on the natural gas pipeline system, and the Commission has already taken steps to address some of the effects. Similarly, changes in the location of gas supply sources have changed flow patterns on the pipeline system. It is important to note that not all of these changes have been adverse, indeed some have been salutary. With regard to changes in gas supply sources, the development of shale gas in the Marcellus region has resulted in abundant gas supplies closer to the consuming region in the Northeast, including its gas-fired generators. Increased gas demand for power generation has led some generators to contract for firm pipeline capacity to meet their gas needs, and pipeline systems have expanded to accommodate the increased demands, thereby making the pipeline grid more robust and adding to the flexibility of the system. Moreover, gas transmission systems have developed additional services to accommodate the needs of gas-fired
generators to access gas supplies quickly in response to electric system dispatch orders. In other instances, generators have installed alternate fuel capabilities for use during periods when capacity becomes unavailable for interruptible gas transportation. While AGA is not endorsing any particular pipeline service offering as the solution for meeting the needs of the electric generation market, these examples demonstrate how individual pipelines and/or generators are creating and developing services to meet the particular needs of the markets they serve. The Commission should continue to be open to creative market solutions to meet the needs of gas-fired generators in ways that preserve the reliability for all existing firm pipeline customers.

4. **Within each day, electricity trading differs significantly from gas trading.**

Similarly, on a day-to-day basis, the various gas markets may not be open on the same days as the corresponding electricity market, especially over Saturdays, Sundays, and Holidays. How should FERC help to harmonize these markets?

As noted above in response to Commissioner LaFleur’s Question No. 3, examining changes to the gas nomination schedule in order to better coordinate with the electric nomination cycles is not a new idea and was very recently addressed without success. Commission’s current policy is that rather than making a nation-wide change in scheduling procedures that affects all pipelines, the issue is best addressed by individual pipelines adding additional nomination opportunities or services to better accommodate specific conditions on their systems to meet the needs of gas-fired generators within their regions. AGA continues to agree with the Commission’s approach to let individual pipelines develop services that would meet the needs of the customers on their systems. AGA therefore urges the Commission not to focus narrowly on

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13 See supra, fn 3.
whether changes could be made to the gas nomination and scheduling procedures as a solution for electric reliability concerns.

5. **What will be the impact of the expected retirements of coal and oil-fired generation on the need for gas and electricity coordination?**

In the aggregate, retirements of coal and oil-fired generation can be expected to lead to an increase in the demand for natural gas for electric generation with the concomitant increased need for more infrastructure and better coordination between the gas and electric industries. This will vary across regions as some regions will see a greater impact on their supply portfolios from expected retirements than others. AGA believes that the effect on reliability of an increase in gas demand for power generation will vary on a regional basis. In some areas of the country, for example, generators will be able to subscribe to excess pipeline capacity or continue to use interruptible capacity to meet their gas transportation needs, possibly in combination with dual-fuel capability. As identified above, however, over-reliance on interruptible capacity by gas-fired generators may affect electric reliability and place an unfair cost burden on existing pipeline customers. In other regions, pressing reliability needs among gas-fired generators may lead to contracts for new services with interstate pipelines, storage providers, or LDCs. In other regions, pipelines may be able to provide individually tailored services to power generators to accommodate growing needs. And, in many regions gas marketers may be able to bring considerable expertise and gas supply flexibility to solve some of the coordination and cost concerns through the use of asset management arrangements. AGA notes that plans by electric system RTOs and ISO’s to increase reliance on gas-fired generation will likely drive decisions as to where optimization of pipeline services and expansion of pipeline capacity might be needed,
as well as the new protocols that will be required to accommodate changes on both the gas and
electric systems.

6. **To what extent should FERC consider modifying its existing Standards of Conduct with regulated utilities—either on an emergency basis or in a more fundamental manner—to assure greater coordination of these industries?**

AGA believes it worthwhile for the Commission to undertake a review of whether its regulatory requirements regarding communications among pipeline operators and electric transmission system operators can be modified to better address the reliability of both systems. AGA notes that section 358.7(h) of the Commission’s Standards of Conduct regulations already permits the sharing of non-public transmission system information if the information pertains to compliance with electric reliability standards or is necessary to maintain or restore operation of the electric transmission system or generating units, or that may affect the dispatch of generating units. However, AGA is aware that some entities are reluctant to participate in regional coordination efforts if certain critical information is being discussed even where an emergency is occurring or has the potential to occur. The Commission should consider clarifying the circumstances under which such non-public information may be shared. In addition, AGA encourages the Commission to examine current practices to determine what types of information are currently being shared between pipeline operators and electric transmission system operators, and whether there are any regulatory impediments to greater information sharing among gas utilities, gas pipelines, electric utilities, power generators, RTO’s and ISO’s where they exist, and other electric transmission operators.
7. **Will progress on this issue be faster if policies are addressed in several “baskets”, such as communication, operation, contracting, and planning/contingency analysis? If so, what are the appropriate “baskets”?**

AGA agrees that steps can and should be taken in the near term to ensure the continued reliability of both the gas and electric systems for all customers, while more comprehensive solutions are implemented to address how closer coordination between the two markets will ensure the reliability of both systems in the longer term. Some issues or “baskets” are appropriately considered to have either a short-term or longer-term focus, while other issues may have both short-term and longer-term implications. While AGA believes that it is worthwhile to group issues topically as a more efficient means of considering potential solutions, AGA cautions that such groupings should not be viewed as mutually exclusive as the issues may be intertwined. Accordingly, AGA urges the Commission to consider gas-electric coordination issues as part of a dynamic timeline.

AGA believes that operational coordination and communication between the gas and electric industries to ensure that adequate gas supplies and services are available to meet the needs of all natural gas customers is an immediate reliability concern to be addressed going into each winter heating season for each region of the country. Likewise, where electric providers have high winter demand that is met with gas-fired generation those needs must be addressed before the winter heating season. AGA therefore encourages the Commission to examine coordination and communication issues to determine whether improvements can be made that would ensure the reliability of both systems as we prepare for the 2012-2013 winter heating season. This may be particularly applicable with respect to the review of the Commission’s standards of conduct noted above.
However, as also noted above, the Commission should undertake such an examination on a regional basis. In addition, the Commission’s efforts in this regard should recognize and differentiate between higher probability and lower probability events on a regional basis. Some regions, for example, enjoy a high degree of gas system reliability but may be affected by events that have a low probability of occurrence but with significant adverse consequences. Indeed, as the Commission’s staff noted in its *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, the natural gas curtailments that occurred during that time were the result of an unusually severe weather event. In other regions, where the gas system infrastructure may not be sufficient to meet all of the desired uses of the system, events threatening gas and/or electric system reliability may have a higher probability of occurrence, yet steps are taken to ensure that all firm customer requirements are met.

Moreover, AGA believes that short-term concerns should focus on improving communication and coordination during periods of peak demand on the gas system, when system constraints or supply or transportation disruptions on the gas system pose reliability concerns for all gas customers. Operators of gas utilities, gas pipelines, electric utilities, power generators, RTO’s and ISOs, and other electric transmission operators must all work together during these periods within the constraints of their respective regulatory regimes to ensure the reliability of both the gas and electric systems.

In addition, other short-term items may fall into other issue baskets. For example, with regard to the “planning/contingency analysis” basket, AGA recommends that the Commission, with the participation of appropriate natural gas industry stakeholders, encourage each regional electric transmission operator or other appropriate body to regularly assess whether there is an over-reliance on interruptible gas transportation service to meet electric reliability needs, given
the level of generator fuel diversity. Such reviews could be conducted by modifying the Order No. 890\textsuperscript{14} planning process or other periodic electric industry planning efforts. These efforts could potentially commence and, in some cases, be completed prior to the upcoming winter heating season. AGA further encourages the Commission to require the various regions to share information and develop best practices for conducting such reviews.

AGA believes that longer-term harmonization efforts should focus on promoting market solutions that provide sufficient incentives for industry to build the infrastructure needed to ensure the reliability of both systems. AGA requests that the Commission clarify at the outset that its preexisting policies regarding cost causation, for both the gas and electric industries, remain strong and undergird any efforts to address reliability through increased gas system infrastructure to meet the needs of all gas customers.

Measures to address reliability, especially the building of gas system infrastructure to reliably meet the needs of all customers, may be costly. Such costs must be borne by those for whom they were incurred. AGA strongly believes that cost responsibility should be assigned early on in addressing reliability issues and adequate cost recovery mechanisms should be addressed to ensure that reliability for some customers is not achieved at the expense of others. Thus, the preservation and enhancement of the reliability of both the gas and electric systems must be coordinated.

E. Summary of Recommendations

AGA recommends that the Commission take a leadership role in quickly convening a series of technical conferences at both the national and regional levels that clearly identify and organize general policy goals and objectives and also address specific regional concerns. Regional technical conferences should address ways in which the natural gas and electric industries can work together to develop appropriate operational coordination mechanisms and communication protocols, scheduling, and cost recovery approaches that would ensure the efficient, safe and reliable operation of both systems, particularly during severe weather or outage events. AGA believes it worthwhile for the Commission to undertake a review of whether its regulatory requirements regarding communications among pipeline operators and electric transmission system operators can be modified to maintain the reliability of both systems. AGA emphasizes that the Commission can provide great value by guiding continued collaboration among all stakeholders on a regional basis.

AGA also recommends that the Commission review existing certificate applications and expedite review and approval of those projects that are needed to enhance system reliability, particularly in those regions facing immediate capacity constraints. Adequate recognition should be given to the need for sufficient lead time to place facilities into service to address capacity constraints.

In addition, AGA recommends that the Commission, with the participation of appropriate natural gas industry stakeholders, encourage each regional electric transmission operator or other appropriate body to regularly assess whether there is an over-reliance on interruptible gas transportation service to meet electric reliability needs, given the level of generator fuel diversity. Such reviews could be conducted by modifying the Order No. 890 planning process or
other periodic electric industry planning efforts. These efforts could potentially commence and, in some cases, be completed prior to the upcoming winter heating season. AGA further encourages the Commission to require the various regions to share information and develop best practices for conducting such reviews.

AGA urges the Commission not to focus narrowly on whether changes could be made to the gas nomination and scheduling procedures as a solution for electric reliability concerns. AGA believes that the Commission should identify the issues and provide necessary policy guidance on potential solutions in advance of directing a standards-setting organization to move forward on implementing a technical solution.

In the longer term, the Commission should evaluate whether its certificating policies provide the correct economic incentives and practical tools needed to bring new assets into service in a time frame consistent with the emerging needs of power generation customers and expectations of continued reliability for all existing customers, both gas and electric.

IV. CONCLUSION

Wherefore, for the reasons stated above, the American Gas Association respectfully requests that the Commission consider these comments in this proceeding and adopt the recommendations set forth herein. In particular, the Commission should move quickly to convene a series of technical conferences at the national and regional levels to clearly identify and organize general policy goals and objectives regarding gas-electric coordination issues that address specific regional reliability concerns. In the end, the Commission must ensure that solutions are not implemented at the expense of the efficient functioning of either the natural gas or the electricity markets.
Respectfully submitted,

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March 30, 2012
Pursuant to the Federal Energy Regulatory Commission’s (“Commission” or “FERC”) Notice of Assigning Docket No. And Requesting Comments (“Notice”) issued on February 15, 2012 in the above-captioned proceeding, Calpine Corporation (“Calpine”) respectfully submits these Initial Comments on the matters posed for consideration in the Notice. Specifically, Calpine offers these comments in response to the set of questions posed by Commissioner Moeller on February 3, 2012 and offers some suggestions on potential next steps.

I. BACKGROUND

Over the past decade, regulators and market participants alike have increasingly recognized the important operational intersection between the natural gas and electric grids. As the nation’s demand for electricity continues to increase, so too have calls for electricity generated in an environmentally responsible manner. These environmental concerns, in turn, have spurred an increase in demand for natural gas-fired generation, a trend that shows no sign of abating. The expanding demand for gas-fired generation, together with the continuing significant shift in the location of domestic gas production, have highlighted the need to ensure our nation’s natural gas infrastructure can adapt quickly to meet these evolving market realities.
In light of the anticipated need for investment in both gas-fired generation and enhanced gas infrastructure, various market participants and industry forums have explored the issues related to the power generation sector’s increasing dependence on natural gas. For example, beginning in 2003, the North American Energy Standards Board (“NAESB”) created a subcommittee known as the Gas Electric Coordination Task Force (“GECTF”). The GECTF was charged with studying whether new standards were needed to improve coordination between the scheduling process for electric and gas transactions.¹ A variety of matters were discussed at length and explored through various committees and subcommittees at NAESB. The GECTF’s most tangible work product was a set of proposed standards designed to improve critical-day communications between the gas and electric markets,² which the Commission eventually adopted in Order No. 698.³ Interest in these areas of cross industry coordination has continued among NAESB participants, and recently the NAESB Board of Directors formed a board level committee (“Board Committee”) to review gas-electric harmonization issues and recommend the best course of action for NAESB.⁴

Because cross industry coordination can impact electric grid reliability, NERC also has analyzed the interdependency of the natural gas and power sectors. Recently, NERC published its “2011 Special Reliability Assessment: A Primer of Natural Gas and Electric Power

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² For example, this set of standards, proposed in NAESB Request No. R04021, requires that RTOs, ISOs, independent transmission operators, and/or Power Plant Operators sign up to receive operational flow orders and other critical notices from the appropriate gas Transportation Service Provider(s).


Interdependency in the United States.” The NAESB Board Committee has identified this NERC publication as one of several base documents for review at the outset of its gas-electric harmonization efforts. Additionally, several ISO/RTOs have re-engaged their stakeholders in the discussions on how to improve the coordination between the electric and gas sectors. Efforts have already begun in NE-ISO, NYISO and MISO.

Enhancing coordination between the gas and electric industries also has become a priority for both federal and state regulators. At a National Association of Regulatory Utility Commissioners (“NARUC”) conference earlier this year, gas-electric coordination topics were discussed, in a session led in part by Commissioner Norris. In early February, Commissioner Moeller requested comments on a set of questions and other text concerning gas-electric interdependence. The Commission further highlighted these coordination issues during its February Open Meeting. At that time, the Commission issued a proposed rule that would amend its regulations to incorporate by reference, with certain exceptions, NAESB’s latest business practice standards for natural gas pipelines. Included in these “Version 2.0 Standards” are further enhancements to the gas and electric industries’ communication procedures which Commissioner Norris noted are a small part of a broader discussion.6 On February 15, the Commission launched a new administrative docket which formalized Commissioner Moeller’s request for comments.7

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7 Coordination between Natural Gas and Electricity Markets, Notice Assigning Docket No. and Requesting Comments, Docket No. AD12-12-000 (issued February 15, 2012).
II. CALPINE CORPORATION

Calpine is a Delaware corporation engaged through subsidiaries in the development, financing, acquisition, ownership, and operation of independent power production facilities and the wholesale marketing of electricity in the United States and Canada. Through various subsidiaries, Calpine owns, leases, and operates 92 natural gas-fired and renewable geothermal power plants in 20 states and Canada with an aggregate generating capacity of approximately 28,000 MW.

III. INTRODUCTORY COMMENTS

As the largest natural gas-fired generator in North America, Calpine is uniquely positioned at the intersection between the electric and gas industries and appreciates the opportunity to provide comments on this important topic. Stated simply, Calpine is in the business of selling electricity. The ability to dispatch and operate our power generation facilities in a safe and environmentally responsible manner is paramount to the company’s success. Calpine’s operations as a power generation company are directly correlated to its ability to obtain the necessary fuel supplies in a reliable, timely and cost effective manner. As an active market participant in virtually every region of the country, Calpine is constantly analyzing market signals in order to appropriately respond to demand while maximizing the company’s ability to generate power in a reliable and efficient manner. We are continually evaluating how to deliver fuel supplies to our power plants, including whether to purchase delivered gas from a third party, purchase gas in the supply region and ship the gas using interruptible or firm pipeline transportation and storage contracts, or a combination of each. On the power side, we must stay abreast of numerous ISO/RTO market rules and interact closely with the real time operators of the ISOs/RTOs. When dealing with the scope and scale of Calpine’s fleet, these can be challenging tasks, but Calpine has been successful in navigating within the various market rules,
regional differences, and fuel supply options. We believe the various forms of gas delivery we use are both adequate and competitive and we see no immediate need for changes.\(^8\)

As noted above, a good deal has been said recently about the increasingly close operational relationship between the gas and electric industries. In some quarters, much consternation exists about the nation’s increasing reliance on natural gas generation and whether this increasing reliance will lead to a less reliable electric grid. We have heard urgent calls to “do something,” with some industry participants making outlandish statements such as “all gas generators must have firm pipeline transportation contracts.” While this “firm up your supply” solution would obviously serve to “firm up” interstate pipeline revenues, it is an extremely severe solution that could add billions of dollars to our nation’s cost of generating electricity while providing, at best, only minor reliability benefits. And while some may urge a change from the status quo, it is worthwhile to note that the current market structure manages to safely deliver 7 Tcf of natural gas each year to reliably meet the nation’s power generation needs.\(^9\)

Additional costs to “firm up supply” would place an extraordinary additional expense on gas generators when it has not been shown that such severe action is needed or that it will appreciably improve reliability. Such additional requirements would, however, have immediate and significant impacts on wholesale electric power prices.

However, even before one can perform an appropriate cost benefit analysis, one fundamental question must be asked: What is meant by “firm service?” Does this mean that a

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\(^8\) If Coal retirements result in natural gas generation becoming baseload units, then our fuel supply needs will likely change again and we may consider increasing our holdings of firm transport.

generator must hold firm transport capacity on a pipeline? What if the generator buys delivered
gas from a third party supplier such as a producer? Would that qualify as “firm service?” How
far up the supply chain does a firm transportation path need to go to be deemed “secure?”
Should firm transportation capacity be required from the well-head to the burner tip? What if the
primary pipeline is fully subscribed? Ill-defined terms such as “firm service” only serve to
confuse the discussion. In order for this dialog to continue in a constructive manner, terms such
as “firm service” must be defined.

Requiring all gas generators to hold contracts for “firm service” on interstate pipelines
will not affect the gas delivery situation for many gas generation plants.¹⁰ Many of Calpine’s
plants are located behind the city gate of local distribution company (“LDC”) systems or are
interconnected with other pipeline facilities over which the Commission does not have
jurisdiction. The Commission cannot mandate that generators hold firm capacity on LDC
systems or intrastates or non-jurisdictional pipeline laterals. Moreover, in many cases firm
service is not available for power generation that is connected to the local LDC. In these
situations, there would be no discernible benefit from holding firm interstate capacity if the gas
remains subject to interruptible delivery once it reaches the LDC or other non-jurisdictional
pipeline systems. It makes no sense to create firm obligations on interstate pipelines without the
possibility of symmetrical treatment at the local level.

Furthermore, the fact that a shipper holds firm transportation capacity up to its maximum
daily fuel requirement does not necessarily afford it the right to swing on that capacity in real-
time. Pipeline firm transportation service typically requires customers to take their gas in

¹⁰ As noted by NERC, “[a] significant amount of electric generation is served by LDCs and intrastate pipelines that
are regulated at the state level.” See NERC Report at pg. 84.
uniform hourly quantities over a 24 hour period, with these uniform hourly quantities calculated based on the shipper’s scheduled volumes. Additionally, in the process of scheduling its system, a pipeline will seek to optimize its unutilized firm capacity by selling short-term transportation services and permitting secondary firm contract paths. Unless a generator schedules its full maximum capacity on a day-ahead basis, it may not be able to make full use of that capacity in real-time. In our experience, if one of our units clears in the day-ahead market or is otherwise called upon before the pipeline’s first day-ahead nomination deadline, we rarely have difficulty obtaining sufficient fuel and/or transportation to accommodate the scheduled dispatch requirements. Problems may occur, however, when a unit that has not been scheduled for dispatch is called upon after the first day-ahead nomination period has passed. This, however, is a timing issue, not an infrastructure issue, and exists irrespective of whether the gas customer holds firm capacity or not.

Equally unfounded is the assumption that firm pipeline transportation contracts represent the only solution to the posited reliability concerns. Pipelines curtail gas shipments, even firm shipments. Furthermore, if a gas generator has not been picked up in the day-ahead market by the ISO/RTO, the generator will not schedule gas deliveries, even if it holds firm capacity. Once the timely nomination deadline passes, pipelines may elect to schedule secondary firm transport, leaving the generator essentially with interruptible service, even if it has a firm contract with the

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11 Given this scheduling constraint, a generator could actually be required to oversize its firm capacity in order to ensure that it will have sufficient firm capacity available during peak hours. This over-contracting would likely result in an overbuilt pipeline system.
pipeline. In light of these real-world circumstances, even firm transportation could be assailed as insufficiently reliable.

In the absence of sufficiently reliable firm transportation, perhaps the only way to provide the “guaranteed” fuel supply that some would impose on gas generators would be to require a dual fuel capability, with some amount of supply on site. This is not a solution that Calpine supports, as the potential cost of compliance would be staggering. Calpine estimates that it would cost approximately $20 million to retrofit one of its plants to allow for 24 hours of oil firing capability. This estimate does not include the cost or feasibility of environmental permitting that would also be required or, if new air permits were triggered, the cost of compliance with current New Source Review standards. Nevertheless, if firm pipeline transportation contracts potentially costing billions of dollars are to be considered, then dual fuel capability should be considered as well.

Requirements for either increased firm transportation capacity or dual fuel capabilities are little more than heavy handed, unnecessary “solutions” in search of an unproven reliability “problem.” If adopted, such requirements would cost the industry, and ultimately electric rate payers, billions of dollars with no discernible benefits. The Commission should decline to adopt such drastic requirements without first conclusively finding that such steps are needed, the benefits of such steps outweigh the significant costs, and that the Commission has the authority to mandate such changes. Calpine submits that these findings have not been, and cannot be, made.

12 While most pipelines offer some form of “bumping rules” that provide firm shippers with the right to bump interruptible nominations for a certain period of time, see NERC Report, page 97, those same pipelines also have “no bump” rules that prevent secondary firm service from being bumped once it has been scheduled. Moreover, these bumping rules and nomination rights are generally limited to interstate pipelines and may not apply to non-jurisdictional LDC and intrastate systems.
Based on Calpine’s experience, the reliability of gas-fired generation does not pose a “problem” in need of Commission resolution. Although impending coal generation retirements have led to increased scrutiny concerning whether there is sufficient natural gas generation, that scrutiny has uncovered no evidence that the trend toward clean-burning natural gas generation is a threat to system reliability. Moreover, there is equally scant evidence that major changes to either the natural gas or the power industry would be needed if this trend continues. The facts are that natural gas generation has been around for decades and has proven to be a clean, efficient and reliable source of electricity. Those facts, coupled with the unprecedented growth in shale gas production, provide ample reasons why the country should continue its conversion to natural gas generation.

Calpine’s generation fleet is relatively new (on average, 12 years old), clean, highly efficient, and ready to take on a more significant role in meeting the nation’s electricity needs. Our facilities are available to meet increasing demand, and we will build new gas generation where the market signals indicate that it is prudent to do so. For its part, the natural gas industry is mature and dependable, and in the era of open access transportation has proven successful at meeting the needs of the market without heavy-handed regulatory intervention.

In the remaining comments below, we respond to the specific questions posed by Commissioner Moeller. Our responses reflect a recurring theme: studies and analyses must be done to better define the nature and scope of the problems to be addressed before any action is taken that will materially change or impact the gas or electric industries. Both industries are working well, and the challenges they currently confront are largely due to issues unrelated to gas/electric coordination. We urge the Commission and the industry to take a step back,
consider the issues, and proceed thoughtfully and without haste in addressing matters of “regulatory convergence.”

**IV. RESPONSES TO COMMISSIONER MOELLER’S INQUIRIES**

A. Specifically, what role should the Federal Energy Regulatory Commission have in overseeing better coordination? What duties, if any, should be delegated to the North American Electric Reliability Corporation (NERC), the North American Energy Standards Board (NAESB), or other entities?

Before the Commission can decide which entities should be involved in overseeing the coordination between the natural gas and electric industries, the first step must be to conduct studies to identify what, if any, problems actually exist. Given its concurrent jurisdiction over the interstate natural gas and power grids, the Commission is an appropriate entity to lead this effort from a national perspective. As it has demonstrated time and again, the Commission is well situated to oversee the process of conducting studies and performing analyses, and to ensure that these studies and analyses are unbiased, comprehensive and conducted by organizations with the requisite expertise.

This Commission-led assessment of what problems, if any, exist and how best to address the problems identified, should carefully study the following matters:

1. **Gas Transportation Serving Existing Gas Generation:** A comprehensive analysis should be performed concerning the flow patterns and capacity factors on the existing pipeline grid (including interstate and intrastate pipelines). The study should assess the extent to which a pipeline’s firm capacity is fully subscribed; actual levels of daily volumes transported throughout the year; whether the pipeline has sufficient capacity to serve its existing customers; and

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13 This list identifies some, but likely not all, areas meriting Commission scrutiny. Although several studies have been performed, none pull together the data in a way that will allow the industry to identify actual areas of concern. As an initial step, the Commission should consider issuing a request for comments on what areas should be studied in order to adequately identify the full range of potential problems requiring review and analysis.
planned expansions or other system modifications that will affect capacity and delivery capability. The study should also analyze existing gas-fired generation facilities, the gas pipelines on which they rely, and the generators’ current capacity factors. This information would provide critical insight into whether current demand levels are being met or whether demand is outpacing pipeline availability. On the power side, the study should analyze how organized markets are managing natural gas generation – is the generation reliable, how much does it run, have the ISO/RTOs encountered system emergencies because gas generators are unable to access adequate gas supplies, etc. Similarly, the bilateral markets should be studied to determine whether gas generators are failing to perform under their contracts and if so, whether this failure has led to reliability problems.

Just recently, the staff of NYISO announced that they intend to conduct this type of comprehensive study. During a March 27 meeting of NYISO’s Electric-Gas Coordination Working Group, NYISO staff reported that they intend to analyze the gas and electric systems in their region, specifically studying issues such as available pipeline capacity over the next 10 years and the costs and benefits of a requirement that all gas generators hold firm transport or have dual-fueled capability. NYISO Staff intends to seek bids from vendors to perform the study. Staff estimates that the study will be completed by the end of 2013.

2. *Estimated coal and oil retirements:* To date, various studies estimating coal and oil generation retirements have been conducted, with widely varying results. Rather than use one of these existing studies, the Commission should institute its own study of anticipated retirements. Such a study should identify the location of expected generation retirements, the time period for these expected retirements, and the likely type of generation that will be built to replace the retired units. Furthermore, no matter the study, some retirement decisions will likely
remain in flux due to many factors, including changes in regulatory requirements, a generation company’s estimations of retrofit costs, the company’s future market price estimates, market response to anticipated retirements, and the results of efficiency efforts and demand response.\(^{14}\) In light of these inherent uncertainties, even a thorough, unbiased retirement study would likely produce only rough estimates of what generation actually will retire and what type of generation will be built to replace those retiring assets.

3. **Critical Load on Electric Systems:** To properly assess the dimension of potential reliability concerns, transmission providers should analyze critical load on their systems. One cause of gas interruptions during the southwest weather related outages was the loss of electricity to critical gas facilities that are powered by electricity. As the FERC and NERC Staffs concluded in their *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, “[t]ransmission operators and distribution providers generally did not identify natural gas facilities such as gathering facilities, processing plants or compressor stations as critical and essential loads...[t]he task force suggests that a review of curtailment priorities be made, to consider whether gas production facilities should be treated as protected loads in the event of load shedding.”\(^{15}\) The Commission should direct that this review be performed.

Once the necessary studies are complete, the industry can then begin to assess regional gas needs and whether the existing gas pipeline infrastructure adequately serves those needs. Based on this assessment, the industry could determine, in an informed way, whether problems

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\(^{14}\) For example, AEP recently announced that it plans to retire more than 4,600 MW of coal fired generation in the SPP and PJM regions, which is a reduction from the 6,000 MW AEP estimated in retirements in an announcement made in June 2011. See AEP Press Release, “AEP Notifies Reliability Organizations Of Planned Plant Retirements” (March 22, 2012) available at [http://www.aep.com/newsroom/newsreleases/?ID=1754](http://www.aep.com/newsroom/newsreleases/?ID=1754).

\(^{15}\) See NERC Report at pgs. 196 and 211.
exist, and what actions may be necessary to address these problems. Moving forward on “solutions” before these studies are performed is a “cart before the horse” approach that promises to waste significant amounts of time, money and effort in the pursuit of standards and rules that are not needed and could result in tremendous increases in electricity prices.

B. To what extent should FERC defer to various regions of the country in addressing these challenges? Should FERC view organized electricity markets differently from bilateral electricity markets? If regional deference is given, what role should FERC play to assure that regional agreements are adhered to?

As noted above, the Commission’s first step should be to study and analyze the actual nature and extent of the challenges facing the industry. Because gas issues differ depending on the region, Calpine expects that, where such challenges exist, they will vary significantly by region. Therefore, it is essential that these challenges be identified and addressed on a regional basis; blanket solutions devised on an industry-wide basis generally should be avoided.

For example, the New England region has encountered challenges in the past with gas supply and pipeline capacity coming into its region. In New York, many gas generators are located on LDC systems, which means that gas generators are dependent on LDCs for gas delivery. California and Texas rely in large part on gas deliveries over intrastate facilities that are not subject to the full array of Commission regulations.\(^{16}\)

In the non-organized markets, where power is sold primarily through bilateral contracts, it must first be determined whether problems exist and if so, how the parties to those contracts wish to address those problems. Bilateral contracts typically address events of nonperformance and specify penalties or damages when either party fails to perform. The Commission should be

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\(^{16}\) In the organized markets with a centralized capacity market, the capacity market is intended to ensure reliability. If reliability issues are a concern, the RTO/ISO is best suited to address those issues, conduct stakeholder meetings, and make changes to its individual capacity market rules if changes are deemed necessary.
reticent about imposing new regulatory requirements that could impact freely negotiated, arms-length contractual relationships between counterparties to a bilateral agreement.

In brief, a one-size-fits-all approach to any new regulatory requirements would be inefficient, unrealistic, inexact, and, more often than not, would address and resolve actual problems only by happenstance. Regional differences must be recognized and solutions devised that take stock of those differences.

C. The expanded use of natural gas for electricity generation is likely to change flows on the natural gas pipeline system. Does FERC need to address this issue?

While natural gas generation is expected to increase due to historically low natural gas prices, Calpine questions whether this increase will significantly impact the flow of gas on interstate pipelines. As new gas generation is built, that generation will presumably be located in high population areas, which are areas currently served by interstate and/or intrastate gas pipelines. We know of no studies suggesting that significant amounts of gas will be needed in areas not currently served by interstate or intrastate pipelines. Consequently, growing demand from gas-fired generation should not dramatically change flows on pipelines. Instead, changes in supply sources, primarily shale gas, have been and continue to be much more likely to shift flow patterns across the pipeline grid. An increasing amount of shale gas is being produced in regions of the country that are not traditional supply zones. (e.g., the Appalachians). For this reason, if gas flows change, the changes are more likely to be attributable to the explosive growth of shale gas development rather than due to an increase in demand by gas-fired generation.

Although pipeline flow patterns may change as a result of shale gas development, the Commission should resist the urge to rush to regulate this occurrence. The natural gas transportation system is a robust, vibrant transportation system that has worked well for more than 50 years, primarily as a result of a healthy combination of regulation and market forces.
Furthermore, the continued expansion of shale gas development provides increased optionality for gas users, thus improving market efficiency and gas generator reliability.

It is already well-demonstrated that market forces will send the appropriate price signals to pipeline customers and pipeline operators, indicating where flows are needed. For example, the recent influx of production in the Marcellus Shale region has resulted in numerous Gulf Coast to Northeast pipelines seeing a dramatic increase in demand for “backhaul” contracts that would bring the Marcellus gas to the South rather than the traditional northerly flow. Those same long-haul lines are seeing an increasing amount of South Texas production moving into Mexico rather than the traditional northeasterly flow. Canada, too, has been affected by increased Marcellus Shale production, as TransCanada’s Mainline interconnects with Tennessee, Empire, and National Fuel Gas. Pipeline crossings at Niagara Falls and Chippewa, New York are predicted to reverse flows within a few years.17 These ongoing changes in flows are driven by market forces and have not required any governmental or regulatory intervention.18

The Commission should allow market forces to work and refrain from prematurely implementing regulations to control the flow of gas. If it can be shown that market signals alone are insufficient to address gas flow issues, at that point the Commission can step in with regulations designed to achieve results similar to those expected from properly functioning market signals.

18 Of course, standard regulatory authorizations for imports and exports are required.
D. Within each day, electricity trading differs significantly from gas trading. Similarly, on a day-to-day basis, the various gas markets may not be open on the same days as the corresponding electricity market, especially over Saturdays, Sundays, and Holidays. How should FERC help to harmonize these markets?

Here again, before taking any action the Commission must identify what problems exist between the gas and electric trading days. As the largest natural gas-fired generator in the country, Calpine has significant experience in dealing with the gas and electric trading days. Calpine has first-hand knowledge of the challenges facing gas generators when scheduling gas and power deliveries. While we agree that improvements could be made, Calpine prefers the current gas and electric trading days and urges the Commission to refrain from taking any action to alter the scheduling periods that could disrupt the markets. We encounter infrequent problems in scheduling gas due to the mismatch between the gas and electric days. Our gas traders are experienced in the industry and are able to manage the scheduling challenges that occasionally arise. Changes such as mandating a 24-hour gas trading day are not needed and could negatively impact liquidity in the gas market. Certain gas trading companies are small but experienced in particular regions of the country. These small enterprises may not have the economic wherewithal to populate a 24-hour trading desk and could close their business rather than incur the expense that would be necessary for a 24-hour trading desk.

With regard to weekend scheduling, Calpine only rarely encounters problems related to the gas markets being closed. For the most part, weekends and holidays are not peak demand periods and any disruption or unexpected weather event can be managed.

Calpine strongly urges the Commission to refrain from making any changes to the gas or electric trading days without fully understanding the need for, and results of, any contemplated changes. Based on our first-hand experience, we respectfully suggest that little need for such changes actually exists.
E. What will be the impact of the expected retirements of coal and oil-fired generation on the need for gas and electricity coordination?

There has been much speculation about potential retirements of coal and oil-fired generation. The various factors driving these retirement projections include historically low natural gas prices, the abundant supply of natural gas, reduced demand due to the downturn in the economy, and impending environmental regulations. Estimates of retirements vary widely, some ranging from 23 GW to 65 GW of retirements. Consequently, the Commission’s first step in analyzing this area of inquiry should be an unbiased analysis of anticipated coal and oil-fired generation retirements, the location of the retired units, and when retirement is expected to occur. The results of this analysis should then be used to identify where new natural gas generation may be built and the extent to which the retired capacity is being replaced by natural gas generation or other types of supply, including demand response or other resources. Once these analyses are performed, the industry will be better equipped to identify, in light of current and future gas demand, whether existing gas infrastructure can support this projected new generation-based demand. Calpine urges the Commission to perform these studies and analyses before deciding next steps.

F. Will progress on this issue be faster if policies are addressed in several “baskets”, such as communication, operation, contracting, and planning/contingency analysis? If so, what are the appropriate “baskets”?

It is difficult to measure progress in solving a set of problems when those problems have yet to be identified. As we have noted repeatedly throughout these comments, it is important to first clearly define the problems to be resolved. After that, it will be easier to determine how best to address the problems and whether categorizing issues and solutions in a particular way makes

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sense. Calpine questions how policy “baskets” can be developed before these necessary first steps are taken.

Even after the Commission properly identifies the range of problems at hand, it likely will become evident that certain solutions will be easier to implement than others. For example, identifying communications deficiencies between the gas and power industries and ways to resolve those deficiencies should be easier than mandating contracting arrangements. The Commission should identify those areas where progress can be made with relative dispatch and focus on those areas first.

V. CONCLUSION

Based on the foregoing, Calpine urges the Commission to consider these comments before taking any action on the matters addressed herein.

Respectfully submitted,

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March 30, 2012
PJM Interconnection, L.L.C. (“PJM”) hereby respectfully submits these Comments in response to the February 15, 2012, Federal Energy Regulatory Commission (“FERC” or the “Commission”) notice requesting comments on the questions posed by Commissioner Moeller on February 3, 2012, concerning gas and electric industry coordination.1

I. Introduction

PJM appreciates the opportunity to provide comments on the important topic of gas and electric industry coordination and thanks Commissioner Moeller for taking a personal interest in leading the discussion. PJM also recognizes and responds to the similarly probing questions from Commissioner LaFleur issued as part of her separate statement on February 16, 2012, in Docket No. RM 96-1-037. FERC is in a unique position to provide leadership given its regulation of both the natural gas and electricity industries. Even though most of the issues need to be solved within the respective industries, FERC can provide necessary support to facilitate the discussion as detailed below.

The natural gas and electricity industries have undertaken a number of initiatives to advance the dialogue including meetings sponsored by industry groups such as the ISO/RTO Council (“IRC”), North American Energy Standards Board (“NAESB”) and the Interstate 

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1 PJM’s comments will also address the questions raised by Commissioner LaFleur at the Commission meeting of February 16, 2012. In addition, PJM is joining the Comments being filed by the ISO/RTO Council on these issues.
Natural Gas Association of America (“INGAA”). In addition, PJM has embarked on a joint effort with NiSource Gas Transmission to work on a number of issues of mutual interest. Although the discussions are in the initial stages, the hope is that in working together at either the company or trade group level, we can reduce or eliminate certain of the barriers that impede the ability of the industries to work together.

As the Commissioner’s February 3, 2012 questions recognize, there are many aspects of this issue, some of which raise generic regulatory issues and others which are more RTO/pipeline-specific. The larger regulatory issues center on how the respective products of the two industries can complement each other to ensure needed supplies of natural gas for electric power generation needs.2

However, broadly, PJM cautions against discussion which offers solutions before the problem to be resolved has been well-defined and thoroughly analyzed. Appropriate problem identification is critical to devising an effective “game plan” to resolving issues and identifying the proper forum for such resolution (whether such forum consists of industry to industry discussions or activity at FERC).

II. Comments

A. Role of FERC

PJM envisions a number of different roles for FERC in the gas/electric coordination discussion. As noted above, targeted discussions through Technical Conferences and other means could be helpful to addressing the larger regulatory questions. These include consideration of:

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2 Obviously, the gas industry also retains critical obligations to the local distribution companies that depend on gas supplies both for winter heating load and for summer injections into storage, where available, to serve winter heating load.
The degree of flexibility available for electric generation customers in scheduling gas transportation to meet their obligations to provide energy in the RTO markets and elsewhere;

Whether enhancements are needed to RTO market rules and capacity rules in non-RTO regions to ensure sufficient incentives to ensure fuel availability and resulting deliverability to electric generation resources;

Whether FERC should consider a fuel deliverability standard to apply to electric generation needed for reliability;

Whether modifications to the existing natural gas firm service product should be considered in order to provide the flexibility and reliability needed for electric generation;

The extent to which Commission precedent and policy in one industry can be applied to the other industry. For example, could the customer options similar to those available to customers exercising demand response in the organized electricity markets be made available through local distribution companies in order to provide more gradations in service levels than might be available under today’s binary firm versus interruptible choices for pipeline service? Similarly, could capacity release opportunities be moved closer in time so as to provide an effective “spot market” for pipeline capacity that complements spot opportunities for purchase of gas, and;

Assessing how the future use of the pipeline system changes given the availability of shale gas in areas of the country that traditionally had imported gas supplies.

Each of these issues is discussed in greater detail below.

On the other hand, a number of the near term operational coordination issues can be addressed initially via industry discussion and cooperation with the two industries reporting
results to the Commission. In many instances, the issue of communications and operations coordination is already under discussion between both industries and is handled on an individual pipeline to RTO basis. However, to the degree that one or the other industry feels that FERC rules unduly inhibit or prohibit communication between the two industries, then those rules may need to be reviewed and clarified. This issue is discussed further below in response to the Commissioner’s inquiry into Standards of Conduct issues.

B. Role of NERC and NAESB

PJM believes that the role of the North American Electric Reliability Corporation (‘‘NERC’’) and NAESB is more of a second-order issue once the full set of issues is best identified and sorted. The role of NERC and NAESB can best be determined once this docket appropriately addresses those issues that might require national regulatory solutions, or those that might require national business practices or standards, as opposed to those issues which merely require more specific RTO to pipeline coordination through bilateral discussions.

C. Regional Differences

The degree to which natural gas has become the fuel source for electric generation varies widely in the US. Resolutions that are developed may not apply equally in all areas of the US power system. For example, natural gas generation contributes approximately 14% of the energy in PJM. While this percentage is clearly destined to increase, natural gas as a fuel source is much more prevalent in other parts of the US. Therefore, any resolution to coordination issues needs to consider the regional differences that exist.

Although it has become somewhat routine for certain commenters to routinely tout the term “regional differences”, in this instance regional differences, both as they exist today and as they will evolve into the future, are significant. The Mid-Atlantic and Midwestern regions served
by PJM could rapidly turn from natural gas importing regions to natural gas exporting regions as Marcellus and Utica shale production increases. Moreover, the impact of various EPA rules are driving a shift toward natural gas generation with incentives to locate those plants very close, if not immediately adjacent, to the larger shale gas deposits. As a result, the use of the existing pipelines may well change over time, lessening the dependence on gas from the traditional supply basins of the Gulf of Mexico and Mid-Continent and potentially reversing flows from this region to the rest of the country.

Nevertheless, PJM believes that the existence of these regional differences today (and their potential widening in the future) should not be grounds for inaction. Rather, the Commission could, on a nationwide basis, commission a national study on the potential pipeline configurations of the future which take into consideration changes in supply and load locations. This kind of review, on a macro interconnection-wide or national level, would assist each region’s planning process and best meld the advantages of a nationwide, high-level overview with the need to respect regional differences that could drive different local solutions.

D. Gas/Electric Market Coordination

There are at least two sets of issues which are worthy of discussion under the heading of “Gas/Electric Market Coordination:”

- Gas/Electric scheduling and market timing issues; and
- The potential for new deliverability products to meet the varying needs of the electric industry.

1. Gas/Electric Scheduling and Market Timing Issues

The gas and electric industries operate large and vibrant markets for both commodity and delivery service in most parts of the country. Each market has grown based on the respective
operating needs of that industry. The rules and scheduling conventions for each market are
different and, in certain cases, create certain conflicts that impact market operations. For
example, gas nominations for delivery scheduling, generally, need to be submitted before the
generator knows its schedule for generation in the organized electric markets in which it may
participate. The risk associated with the difference in scheduling rules has been borne and
managed up until now by the generation owners through their energy market offers. The
relationship of nominating gas delivery versus electricity market clearing does not necessarily
require a single integrated market schedule since market participants still have avenues, albeit
imperfect, by which they can manage risk. Yet, the different market scheduling practices each
developed in a vacuum from one another, such that there has not been a thorough vetting of
whether additional synergies between the two markets can be achieved.

As a result, PJM recommends that discussion in this area should focus on the following
potential areas for improvement:

• Ensuring more transparency between the gas and electric markets so that unit owners can
  have ready and coordinated access to pipeline capacity that may be released in one
  market (such as where a unit owner’s bid did not clear) where released capacity can serve
  another RTO market or another generator within that RTO market;

• Ensuring more transparent and ready access to information so that the entity with
  reliability authority for electric markets can easily verify the deliverability of gas supplies
  on a given day when pipeline pressure or deliverability issues might affect such
  deliverability;

• Conversely, enhanced transparency and communication from the RTOs in charge of
  electric reliability to the pipeline operators on the reliability needs of the power system so
as to allow pipelines to make informed decisions regarding the curtailment of interruptible customers so as to maintain pipeline reliability;

- Developing a more coordinated and simplified information source for system operators to more easily identify particular operational challenges that may affect the gas pipeline system as a whole along with impacts on particular pipelines, and;
- Ensuring that there is greater liquidity for entities which need to release or secure unused pipeline capacity due to changes in real time load conditions.

2. Issues Associated with Firm Transportation for Capacity Resources

The pipeline industry has argued, on a national level, that the Commission should institute comprehensive requirements for all electric generation capacity resources to purchase firm transportation. Like other issues in this proceeding, the merits of such a resolution needs much further examination so as to avoid identifying solutions before a proper scoping of the problem to be solved.

Fuel deliverability should not be narrowly focused solely to a discussion of purchasing firm transportation service. Rather, the larger issue entails an examination of what should constitute an acceptable level of security of fuel supply (and deliverability of such supplies) for those resources which are deemed capacity resources. This larger issue also requires an examination of whether current market rules provide sufficient financial consequences for generating unit unavailability for any reason including insufficiently dependable access to fuel.

Approximately 28,153 MW of capacity resources in PJM are dual fuel resources. Reliable supplies of oil or the availability of natural gas supplies from more than one pipeline (as well as directly from producer wells and short haul pipelines in the Marcellus shale region) can, in some cases, supplant the need for firm transportation service from a particular pipeline. Moreover, if a
business decision by a generation owner to forego firm transportation results in the unavailability of the generation unit when needed most, the unit owner may face financial penalties through PJM’s RPM Capacity Market and will not earn net energy market revenues that are crucial to the financial viability of the resource going forward. Although the particular results of plant specific analyses will differ by plant and by RTO region, it would only be appropriate to explore whether some overarching national criteria on deliverability is worth considering if the Commission finds current market rules do not provide sufficient incentives to secure availability of fuel supplies, and to avoid one region of the country (such as a region without a forward capacity market) “leaning” on the gas deliverability paid for by an adjoining region.

Moreover, any focus on deliverability issues should not be limited by the paradigm of today’s definition of what constitutes “firm” transportation service. Today’s “firm” transportation product was designed years ago around the needs of local distribution companies to be assured of supplies to meet the needs of winter heating consumers and to meet the state “obligation to serve” requirements placed on such local distribution companies. That same firm product does not necessarily fit the reliability requirements of an electric system which is largely summer peaking and which is made up of a host of different types of generating units with different environmental run restrictions, ramp rates and maintenance schedules.

Given these very different requirements, simply requiring that all generation be obligated to purchase today’s firm transportation product may very well be trying to wedge the proverbial round peg into a square hole. PJM would recommend a more robust discussion on the nature of today’s firm product and whether variations on that product are in order to meet the needs of the electric industry. Issues for further examination include consideration of the following questions:
• Are there appropriate variations on the traditional firm product that best recognize the reality that the electric grid is largely summer peaking while still ensuring deliverability during the winter period?

• Is the product appropriately priced to recognize the different levels of capacity available on different pipelines both in the winter and in the summer months?

• Is there a variation on the firm product that could still ensure appropriate planning for the future needs of the electric grid while not requiring the industry to pay for a degree of service designed around winter peaking needs when the electric industry’s deliverability needs are largely focused on the summer period?

• Finally, just as demand response has become ubiquitous in electricity markets as one tool for meeting peak demand, the customer choices available under demand response programs, and the compensation afforded customers who serve as demand response capacity resources, could provide a potential template for more dynamic real time management of pipeline deliverability issues. PJM has most recently filed with the Commission to institute price responsive demand as another tool to recognize the impact of demand response on addressing peak day conditions. Although FERC’s regulation of pipelines does not include the commodity itself, there are analogies from the demand response tools that RTOs have developed that could be useful as pipelines seek to better manage real time operations in response to a changing load profile. Such tools could also energize today’s capacity release markets by moving them closer and more responsive to real time conditions just as is the case with customer demand response in the wholesale electricity markets. These and other issues should be explored further with the Commission and the States so that many of the lessons learned in the electric industry can
be considered in examining ways to increase the efficient operation of the nation’s pipeline system and vice versa.

PJM believes these are fundamentally regulatory questions best addressed at the Commission level. PJM stands ready to assist in any Technical Conferences or other Commission initiatives addressing these generic regulatory issues surrounding the definition of firm service.

E. Standards of Conduct

Both electric system operators and gas pipelines (in their operations function) reside on the same side of the Code of Conduct, in the sense that we both possess transmission information about our respective systems that cannot be shared with the market participants. While PJM believes that current rules do not pose a regulatory impediment in the sharing of transmission information between the gas and electric industries, it has been suggested that the guidance from FERC may not be as clear. As a result, it would be appropriate for the Commission to consider, as a threshold matter, making clear that the standards of conduct permit reliability information to be shared confidentially between electric and gas transmission system operators while still ensuring that confidential information is not inappropriately or prematurely released to the marketplace. PJM believes this issue is one which should proceed on an accelerated regulatory track while the larger policy issues in this docket are being discussed and debated.

In a larger sense, greater coordination of the short and long term reliability issues facing each industry is in order. The two industries have become more intertwined than ever before, yet the terminology and cultures of the two industries have not progressed as far so as to ensure the level of reliability coordination that will be needed in the future. To date, gas pipelines are largely outsiders to RTO reliability issues and the NERC process, while electric market
participants are similarly distant from pipeline reliability and regulatory issues. For the most part, operational issues still need to occur largely on a bilateral basis between the system operators and the pipelines that serve their region. Nevertheless, forums such as this one are appropriate to prompt communication on the larger issues of coordination that are addressed in these comments and others filed in this docket. It is in the mutual business interests of the gas and electric industries that cooperation efforts continue and are successful. The Commission should continue to encourage such communications by “asking the right questions”, as is being done in this proceeding, when particular case-specific regulatory issues are presented that could affect the efficient operation of the other industry.

F. Impact of Coal Retirements

The implementation of EPA regulations will bring significant impacts to both the gas and electric industries. PJM anticipates the retirement of, at the very least, 18,000 MW of coal-fired generation over the next 5 years. It is evident that most new generation additions will be gas-fired. However, the impact of coal retirements is twofold: (1) replacement of coal-fired generation capacity with natural gas; and (2) reduced short-term coal capacity during the outages that will be necessary to install abatement equipment for those plants that will retrofit.

PJM is examining the proposed schedules for “tie-in” of new pollution abatement equipment along with the generation retirement schedules. Early notice from generators as well as the availability of the “Reliability Safety Valve” process adopted by the EPA has made this process more manageable, although coordination challenges may still arise. PJM’s planning process provides an open transparent means for all aspects of the industry to stay apprised of these matters. Although PJM does not foresee any gas-electric reliability coordination issues during these Spring and Autumn shoulder periods as winter heating demand power demand will
not be at their respective peaks. PJM welcomes the input from the gas pipelines serving its region to identify any particular issues which they foresee arising during this period.

Coordination of maintenance activities between the gas and electric industries could require the exchange of maintenance plans and more importantly, a level of coordination on each side to assess the respective interactions of the systems, so that conflicting activities are identified and mitigation plans developed. Getting to this level of understanding will take a continued concerted effort on the part of both industries. Appropriately, there is a growing recognition that a much closer relationship is needed and the two industries are working to develop the necessary working relationships.

G. Baskets of Issues

In consideration of the request to identify and sort “baskets” of issues, we offer the following:

- **Code of Conduct** – Review previous guidance on the Code of Conduct and provide clarifications to the industries, based on the present situation, if necessary.

  *RECOMMENDED FORUM:* FERC.

- **Operator Communications** – Individual entities continuing to work with their respective counterparts to better understand each other’s business and provide training and guidance to bridge any gaps in language and procedures. Additionally, encourage cross communication between the respective operator teams in emergency situations.

  *RECOMMENDED FORUM:* Industry bilateral discussion and IRC/INGAA meetings with potential reports to FERC.

- **Generic Scheduling/Market Issues**---Potential area for a targeted Technical Conference focused on an examination of issues surrounding coordination of information, scheduling
and driving greater efficiencies in the release of unneeded gas transportation capacity.

RECOMMENDED FORUM: FERC.

- **Deliverability Analysis**—Commission a nation-wide review of the impacts of shale development on future pipeline demands and operations. **RECOMMENDED FORUM:** FERC with industry and stakeholder input.

- **Deliverability Issues**—Potential area for a targeted Technical Conference focusing on whether a more generic deliverability standard should be developed as well as whether refinements should be made to today’s firm and interruptible products in order to better meet the needs of the electric power industry. **RECOMMENDED FORUM:** FERC *(Technical Conference with Supplemental Comments).*

### III. Conclusion

PJM appreciates this opportunity to comment and stands ready to serve as a resource to the Commission as it considers this important topic.

Respectfully submitted,

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Pursuant to Commissioner Moeller’s February 3, 2012 Request for Comments\(^1\) and the Federal Energy Regulatory Commission’s (“Commission” or “FERC”) February 15, 2012 Notice Assigning Docket No. and Requesting Comments,\(^2\) the New England States Committee on Electricity (“NESCOE”) hereby files these comments in the above-captioned proceeding.

NESCOE is the Regional State Committee for the New England region. NESCOE is governed by a board of managers appointed by the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont and is funded through a regional tariff administered by ISO-New England, Inc. (ISO-NE). NESCOE’s mission is to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest reasonable cost over the long term, consistent with maintaining reliable service and environmental quality.


\(^2\) Coordination between Natural Gas and Electricity Markets, Notice Assigning Docket No. and Requesting Comments, Docket No. AD12-12-000 (Feb. 15, 2012).
I. Communications

Pursuant to the Commission’s Rules of Practice and Procedure 203 and 2010,3 the persons to whom correspondence and other papers in regard to this matter should be addressed and whose names are to be placed on any Commission official service list that may be developed are designated as follows:

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II. Comments

NESCOE appreciates Commissioner Moeller and the FERC undertaking this important examination of coordination issues between the gas and electric markets. As Commissioner LaFleur observed in her statement issued in connection with Docket No. RM96-1-037, this issue has been of particular concern to New England since January 2004, when an unusually cold weather condition, referred to as New England’s 2004 Cold Snap, increased the demand for gas for heating and threatened the availability of gas for electric generators. In response, New England developed new operating procedures that were approved by the Commission.4 Those procedures helped, but did not fully resolve, gas and electric market coordination issues in New England.

Today, ISO-NE, stakeholders and the New England states are further considering important gas-electric industry issues in the context of New England’s Strategic Planning Initiative5 and in the context of redesigning New England’s Forward Capacity Market.

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For example, there are potential market-based solutions to some issues noted below that may address elements of New England’s gas-electric coordination concerns. As FERC considers the important issues raised in the request for comment, and the constructive role FERC can and should play in addressing some of them, FERC should do so in a way that allows regions to tailor solutions to conform to and work comfortably within their markets.

In recent years gas-fired generating capacity has supplied nearly half the region’s electricity demand. In the future the prevalence of gas-fired generating capacity is likely to increase as older coal and oil-fired generators retire and additional flexible gas-fired plants are needed to balance growing reliance on intermittent renewable power. With this growing dependence on gas in mind, our proposed measures to improve coordination involve changes in the way both industries operate.

In these comments, NESCOE offers its view on the appropriate federal agency to assist in the resolution of these issues; the need for regional resolution to many of the issues, tailored to specific regional problems, their timing, and markets; and identifies and offers observations about coordination issues and potential solutions for some of them.

A. FERC Is the Appropriate Federal Agency to Address Industry Coordination Issues that Are not Amenable to Resolution by Regions

FERC is the appropriate entity to facilitate discussions, mediate disputes, and decide in instances where parties are unable to reach agreement to resolve problems in connection with gas and electric market coordination issues. Specifically, FERC has authority over the expansion of interstate gas pipelines and gas storage facilities and over the rates charged by gas transmission companies; has an oversight role in the wholesale electric power market; regulates the market design and tariffs of the Regional Transmission Organizations (RTOs); and through oversight of the wholesale power market, FERC can influence generators with respect to procuring gas.
Moreover, while the coordination challenges facing the gas and electric industries influence the reliability of both, the challenges discussed below are not fundamentally technical in nature. Accordingly, potential solutions are generally not technical in nature and resolutions are highly unlikely to be achieved through new engineering approaches. Accordingly, FERC, rather than either the North American Electric Reliability Corporation (NERC) or the North American Energy Standards Board (NAESB) is the appropriate entity to facilitate coordination issues between the gas and electric markets.

B. To the Extent Problems Are Able to be Resolved by Regions through, for Example, Modifications to Market Rules, FERC Should Give Deference to Regions to Tailor Solutions to Regional Markets and Issues

The specific nature of gas and electric industry coordination problems is likely to vary regionally, and so appropriate solutions will likely also differ regionally. While FERC is the appropriate federal entity to ensure issues between gas and electric markets do not adversely affect reliability, FERC should in the first instance allow regions to identify and implement solutions tailored to regional problems and market structures, in conjunction with other regions, when applicable. Where regions are unable to develop and implement solutions, FERC should address remaining industry coordination problems on a regional basis.

For example, in New England, which has a relatively large winter gas heating load and where fuel options for new or replacement generating capacity are very limited, coordination problems are already having a deleterious effect on the efficiency of the energy market and raising concerns with respect to reliability. These coordination problems are likely to be exacerbated in the near future by expected retirements of coal- and oil-fired generating capacity. ISO-NE projects that 7.3 GW\(^6\) of existing generation in

\[\text{Study prepared for ISO-NE’s Planning Advisory Committee by ICF International presented December 14, 2011 (http://www.iso-ne.com/committees/comm_wkgrps/prtcnts_comm/pac/mtrls/2011/dec142011/gas_study_public.pdf)}\] This so-called Gas Study is in draft form at this time. NESCOE and other stakeholders have urged ISO-NE to be cautious about
New England will retire between now and 2020 and 8.5 GW\textsuperscript{7} will retire between now and 2030. These retirements will likely be replaced to a significant degree by additional gas-fired generation. Accordingly, ISO-NE, market participants and the New England states are already in the process of discussing potential solutions. By contrast, in other regions, the winter heating load may not be as large compared to industrial and electric power generation demand, thereby allowing other regions more time to address the coordination issues. Further, New England has a competitive wholesale electricity market, which could be adjusted to resolve some coordination issues without injecting mandated national regulatory solutions that may unintentionally interfere with the operation of the wholesale markets. On the other hand, in areas that do not rely on competitive markets, mandated regulation-based solutions may be more appropriate.

If regions do not identify and implement solutions to their unique set of problems, it could be appropriate and constructive for FERC to play a mediating or adjudicatory role. Once the region implements solutions to coordination issues FERC should, of course, oversee and enforce the agreements.

With regard to the request for input on whether creating “baskets” of issues might help resolve issues more expeditiously, NESCOE encourages FERC to allow each region to work on those issues the region identifies as able to provide near-term improvements without being constrained by pre-defined categories. This may help expedite regionally tailored solutions appropriate for region specific issues.

drawing any conclusions about how to most cost-efficiently solve a potential natural gas supply issue before all potential solutions have been thoroughly evaluated. The natural gas issue is complex and starts with operational reliability but has a host of potential solutions, only one of which is the region’s customers investing in more pipeline capacity. For example, there are changes that could be made to the market rules to encourage different behavior by both generators and system load that could satisfy any identified needs. These types of changes could mitigate or even eliminate any pipeline capacity shortfall that the Gas Study may ultimately establish.

C. Observations on a Range of Gas-Electric Industry Coordination Problems and Potential Solution Space

*A mismatch in the scheduling and delivery timelines* between the gas and electric industries appears to cause operational and market participation problems for both the gas and electric industries. The scheduling conflicts stem from the fact that the scheduling of gas shipments occurs before generators know whether their bids to provide power in the day-ahead energy market have been accepted. While gas pipelines offer a later day-ahead nominating period and two intra-day nominating options, these nominating periods typically involve smaller gas volumes (and in tight gas situations perhaps no spot gas) and are also misaligned with ISO-NE’s day-ahead and real-time market scheduling.

**Potential Solution Space:** ISO-NE intends to implement additional flexibility in its day-ahead energy market scheduling by adding re-offer periods. ISO-NE’s modifications will not, however, correct the underlying mismatch in day-ahead gas and electric scheduling, which are an appropriate subject for FERC-directed and supervised discussion and resolution.

*The mismatch of gas and electric “days” or delivery times is a related problem.*

The gas delivery day is a 24-hour period beginning at 10:00 AM eastern time on the day ahead, while in ISO-NE’s wholesale electricity power market, the day runs midnight to midnight. This misalignment of gas and electric “days” leaves power generators unable to be certain of gas availability for the entire electric day. This can lead to operational as well as market difficulties. For example, a generator must commit to be available to the electric market without knowing the availability of fuel for the second part of the electric day (hours ending 1100 through 2400). If this gas is ultimately not available (via pipeline restrictions on gas flow), this can result in generators falling off-line at 10:00 AM. This puts generators at risk for real-time price and volume deviations from their day-ahead market responsibilities and potentially creates reliability issues for the system operator in dispatching replacement power. Alternatively, in the absence of flow restrictions, generators who did not nominate day-ahead gas can continue generating, honoring their
commitment in the electric market, but potentially causing operational flow issues on the gas pipelines. Either of these outcomes can lead to reliability and financial challenges in the region for both the electric and gas system operators.

For those wholesale electric markets’ that need to balance generation and electric demand in real time using gas-fired capacity there are inherent conflicts with the limited intra-day operational flexibility of gas pipelines. Historically, before the introduction of significant amounts of gas-fired generation, there was little need for gas pipelines to accommodate intra-day variations in gas usage. Accordingly, gas pipeline procedures offer limited flexibility to handle intra-day variations in gas usage. However, today, in ISO-NE’s wholesale electric market, gas-fired generators are typically on the margin, with coal, hydro and nuclear units providing most of the base load energy. In this marginal position, gas-fired units are the units that will be ramped up and down during the day as electric demand changes or in the event of a contingency. Additionally, gas fuels many of the quick-start units needed to balance system needs in times of unexpected load usage or loss of generation. The wholesale electric market requires that its marginal and quick-start units be flexible. This concern is likely to be exacerbated in the future, as New England becomes more reliant on gas-fired capacity, due to the projected retirement of the region’s older coal, oil and possibly nuclear units and the projected need for more gas-fired quick-start units to respond to sudden changes in output from intermittent renewable resources.

Potential Solution Space: There is a need for concerted effort by both the gas transmission companies and Regional Transmission Organizations to craft operating procedures and tariffs that bridge the inherent mismatch. Stakeholders should also explore whether strategically located storage supply would assist generators in stabilizing their ability to run during times of gas pipeline constraints.

The gas markets are more flexible with intraday trading than the wholesale electric markets. Gas pricing and availability can change during the intraday period for various reasons but the electric generators may only be able to revise price once prior to the start of the real time electric day.
**Potential Solution Space:** Hourly real time offering intervals should be implemented in the wholesale electric markets. While some wholesale electric markets may offer this feature or may be considering it, hourly real time offering should be available in all markets.

**Commitment to new/expanded gas pipeline capacity exposes differences in risk tolerance between gas market participants and electric generators.** The types of companies that bid in pipeline open seasons include Local Distribution Companies (LDCs), gas marketers, and gas producers. Gas LDCs that make commitments for firm capacity, which commitments receive regulatory approval, are generally allowed to recover the costs of that firm capacity through retail rates. Gas marketers (that may also supply some gas to LDCs) take the risk of making commitments to future firm pipeline capacity in order to be in a position to offer gas availability. Gas producers that contract for firm capacity seek to secure access to the markets for their gas. By contrast, in a competitive wholesale electric market such as New England, generators are not guaranteed recovery of their fixed costs, including any commitments to pipeline capacity, and therefore have minimal financial ability and/or risk tolerance to sign a contract for long-term pipeline capacity.

**Growing gas demand for electric generation threatens the historic economic benefits of non-firm gas sold to the electric sector.** Historically, accommodating gas-fired power generators on pipelines has to some degree benefited existing firm customers of the pipelines. LDCs’ gas consumption is highly seasonal. By incorporating gas-fired generators whose demands are generally counter seasonal, the year-round utilization rates of the gas transmission lines improved and the costs to firm customers decreased (as firm capacity holders sold their excess capacity on a spot basis). While there is still a very high degree of counter-seasonality to the gas demands of the electric power sector in New England, the trend towards gas-fired generation on the margin (and the expected future growth in demands for gas-fired generation to complement the intermittent nature of renewable resources) has led to increasing competition between electric generators and firm pipeline customers over winter gas pipeline capacity.
There is an inherent tension between gas pipelines, which operate in a world of long-term firm contracts, and electric generators, which function in a spot environment with no guarantee of recovering their fixed costs. In regulating pipeline expansions, FERC requires that existing pipeline users not fund expansions from which they do not benefit. Therefore, FERC requires that requests to build or expand gas pipeline facilities be accompanied by evidence of firm contracts. This ensures that existing customers are not at risk for paying for new capacity. By contrast, New England’s wholesale electric market has been designed to minimize marginal costs on daily and even hourly basis. By definition, dispatch on the basis of marginal costs does not assure recovery of any fixed costs.

Potential Solution Space

Potential Modifications to the Wholesale Electric tariffs:

- Supplemental capacity payments for generators that commit to firm gas supply (for a percentage of the capacity or for the winter season) or alternatively, reduce capacity payments for lack of firm gas supply;
- Requirements that gas-fired generators without firm gas supply have back-up fuel capability for the winter season or make some portion of the capacity payment subject to having back-up fuel capability; or
- Stricter performance standards so that generators that fail to follow dispatch due to a lack of gas are subject to penalties sufficient to encourage adequate fuel supply.

Potential Modifications to Gas Pipeline Practices:

- More flexible contracting options for firm pipeline capacity, for example seasonal blocks, or shorter commitment periods than the traditional long term contracts;
- Rate incentives for pipelines that implement flexible contracting terms for firm capacity; or
- Innovative operating practices that increase load factor during peak load periods.

Texas Gas Transmission has just completed a FERC authorized two-year pilot program for winter no-notice service (winters of 2010/2011 and 2011/2012), which allowed generators to sign short-term gas contracts during the winter months. Based on the success of this trial, Texas Gas Transmission is currently requesting that FERC permanently allow the offering of this service. (Inside FERC, March 26, p. 5).
Additional difficulties exist due to differences in time horizons in planning gas pipeline expansion, electric transmission expansion, and generation capacity expansion. In New England’s Forward Capacity Market, capacity purchases are currently made approximately three years ahead of the delivery date. This is not synchronous with the gas transmission companies’ planning time horizon, which looks ten years ahead. It is also not adequate lead-time to properly plan, permit and construct gas pipeline expansion if the region concludes after evaluating ongoing studies and solution options that such expansion was necessary and is the most cost-effective solution. Whether there is a need for gas pipeline or storage expansion in New England is to be determined, and thus the question whether the planning time horizon must be resolved remains to be determined.

Potential Solution Space: With regard to time horizons associated with generation capacity and transmission expansion, New England is currently considering better aligning markets and planning in the context of Strategic Planning Initiative discussions and potential modifications to the Forward Capacity Market.
III. Conclusion

NESCOE appreciates the Commission’s initiative to explore the important issues raised in the request for comment and the opportunity to provide our views. NESCOE looks forward to further participation in the dialogue about gas-electric industry coordination going forward.

Respectfully submitted,

/s/ Dorothy Capra

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Date: March 30, 2012
Coordination between Natural Gas and Electricity

Docket No. AD12-12-000

COMMENTS OF THE
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

In accordance with the Commission’s February 15, 2012 Notice Assigning Docket Nos. and Requesting Comments (“Notice”) in this proceeding, the New York Independent System Operator, Inc. (“NYISO”) respectfully submits these comments. The NYISO is also a signatory to the Joint Comments1 of the six Commission-jurisdictional Independent System Operators and Regional Transmission Organizations, which are being filed concurrently.

The NYISO agrees with the Joint Comments that the Commission has an important role to play in promoting better communication and coordination between the natural gas and electric industries. The Commission should hold national level technical conferences to bring the two industries together to discuss the most important coordination issues. It seems likely that these discussions could lead to new national policies or rules on a number of subjects. As noted in the Joint Comments, however, there are also issues that it would be useful to consider at the national level but that will not lend themselves to “one-size fits all” solutions. In these cases, the Commission should defer to the regions and allow them to craft solutions, or to conclude that no solutions are needed, as individual circumstances warrant.

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The NYISO has taken, and is in the process of taking, a number steps to enhance communications and coordination between the gas and electric industries in New York. New York’s *Gas-Electric Coordination Protocol*, which was implemented in response to Order No. 698,² has worked well. There is room to improve gas-electric industry communications protocols in non-emergency situations, including, *e.g.*, with respect to the scheduling of gas infrastructure maintenance outages. Such improvements can likely be achieved with the Commission’s encouragement without requiring more direct action.

The NYISO recently established a stakeholder Electric Gas Coordination Working Group that is providing a forum for greater inter-industry communication and coordination. The initial focus of this Working Group has been on educating members on both electric system and gas system operations and issues. The NYISO has found this forum to be highly valuable for its staff and stakeholders, and it appears to be of value for gas industry participants. The NYISO encourages the Commission to conduct similar forums on the national level, as was done at the FERC-NARUC Collaborative in February, to further facilitate education and communication between these industries on issues that impact each other. The NYISO was honored to participate in the FERC-NARUC Collaborative panel, and stands ready to support similar industry efforts led by the Commission.

The NYISO is also already working with neighboring systems to define the scope of a study of the adequacy and security of the interaction of the gas and electric systems in the Northeast, Midwest, and Ontario. The NYISO agrees with the *Joint Comments*’ recommendation that the Commission consider conducting or sponsoring an independent study.

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to evaluate the anticipated effects on pipeline flows of the increased use of natural gas in electric

to evaluate the anticipated effects on pipeline flows of the increased use of natural gas in electric
generation driven by shale gas production and other fundamental changes. As was noted in the
Joint Comments, a national study might also explore the potential supply chain consequences of
such changes, including their impacts on gas-fired generation. The scope of the study, the
timetable for its completion, and related issues could all be addressed at national level technical
conferences.

The New York State Reliability Council already has rules requiring dual-fuel capable
units in New York City and Long Island to switch to oil when electric loads reach defined peak
thresholds, which are adjusted for both summer and winter peak conditions. The NYISO
administers these rules in conjunction with Consolidated Edison Company of New York, Inc.
and the Long Island Power Authority, to avoid the potential that a loss of gas fuel supply could
lead to an electric system outage. These rules help to make the electric system less vulnerable in
the event that natural gas becomes unexpectedly difficult to obtain. The NYISO believes that
other regions might benefit from developing additional dual-fuel generating capability and/or
fuel switching requirements, but recognizes that there may be reasons why this may not be a
desirable option in certain regions.

Differences between gas and electricity market scheduling timetables have not posed a
problem in New York. The Commission concluded that there was no need to change NYISO
market timetables to better coordinate with the “gas day” in 2006. ³ Nothing has changed since
then to alter that conclusion. The NYISO also believes that most of its stakeholders are satisfied

³ California Independent System Operator, Inc., et al. 120 FERC ¶ 61,206 (order terminating
Section 206 proceedings for each Commission-jurisdictional ISO/RTO that had been initiated to examine
“if additional procedures are needed to determine whether their scheduling and compensation
mechanisms need to be revised to ensure that gas-fired generators can obtain gas when the gas-fired
generation is necessary for reliability”).
with its existing electricity market timetable and would not favor changes to it. Thus, while it may be productive for issues related to the gas and electricity trading days to be discussed at national level technical conferences, the Commission should not begin with a presumption that greater “harmonization” is needed in all regions.

In conclusion, the NYISO respectfully requests that the Commission accept the recommendations set forth in these comments.

Respectfully Submitted,

/s/ Ted J. Murphy
Ted J. Murphy
Counsel to

March 30, 2012
CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list complied by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (2011).

Dated at Washington, DC this 30th day of March, 2012.

By: /s/ Ted J. Murphy
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Transmission Planning in the Northeast after Order 1,000
Transmission Planning in the Northeast after Order No. 1000

Steven T. Naumann
Vice President, Transmission and NERC Policy
Exelon

Energy Bar Association
Northeast Chapter Annual Meeting
June 6, 2012

Planning
- Switch from bright-line and use of scenarios and sensitivities
  - How will decisions be made?
  - How will elimination of bright-line criteria affect siting?
- Consideration of Public Policy drivers?
  - Order No. 1000 defines considering transmission needs driven by Public Policy Requirements as (1) identification of those needs; and (2) evaluation of potential solutions
  - Does this mean after the two steps are done the Transmission Provider has met the requirements of Order No. 1000 and do no more?

ROFR
- Exactly what ‘rights’ go with sponsorship?
- How much deviation from sponsored project is allowed before it is not a sponsored project?
  - Will Primary Power, LLC v. RM Interconnection, L.L.C. (Docket No. EL12-69, filed May 16, 2012) provide guidance or being that the dispute is prior to the Order No. 1000 compliance filings is this situation unique?
- What makes a sponsored project? Lines on the map do not. How much detail and analysis?
- How does the transmission planner decide which entity should construct? Rigid formula or factors to consider (not every project is the same). Can data be submitted as confidential? Should this be left to siting agency?
- Who will do the O&M, NERC compliance? Is a promise of a contract enough?
- Reliability backstop issues.
- ROFR is likely to be an issue for which disputes will continue.
Cost Allocation
- Has been contentious; where not contentious, not likely to change
- Guidance from FERC order on remand of PJM cost allocation
- But, in some regions likely to see continued litigation
- Inter-regional cost allocation likely to be difficult
  - Prior instances of attempts at unilateral allocation
  - Midwest Independent Transmission System Operator, Inc., 133 FERC ¶ 61,275 (2010), reh'g pending (Michigan PARS)

Next Steps
- Regional compliance filings in October 2013
  - Work pretty far down the road
- Inter-regional compliance filings in April 2013
  - Work has hardly started
- Appeals
  - One appeal filed in 7th Circuit (SMUD), two others in DC Circuit (Coalition for Fair Transmission Policy, South Carolina Public Service Authority)
To: NEPOOL Order 1000 Work Group & ISO-NE  
From: NESCOE  
Date: January 9, 2012  

The New England States are pleased to provide to NEPOOL’s Order 1000 Work Group and ISO-NE the states’ draft framework to address FERC Order 1000’s provisions concerning public policy projects and associated cost allocation. The framework reflects compromise on behalf of all states and underscores the states’ collective interest in addressing our challenges as a region.

The draft framework is set forth in sufficient detail to enable discussion of its specifics. It is not styled as a tariff. Over the coming months, we look forward to input from stakeholders and ISO-NE and further refinement of the framework’s details.
New England States’ Draft Framework

FERC Order 1000 – Public Policy Projects & Associated Cost Allocation

1. Notwithstanding the states’ right to request an Economic Study on an annual basis pursuant to Attachment K, ISO-NE shall allocate to NESCOE no less than one study (“Public Policy Study”) not less than once every two years to enable analysis of the potential implications of legislative and regulatory requirements (“Public Policy Requirements”) and/or public policy targets that the states collectively identify and communicate to ISO-NE and the Planning Advisory Committee (“PAC”) pursuant to the procedures set forth below.

2. Prior to communicating to ISO-NE the scope of such Public Policy Study and related parameters and assumptions, NESCOE will solicit stakeholder input on which, if any, Public Policy Requirements drive transmission needs and are appropriate to consider in regional planning.

NESCOE will accept such stakeholder input through written comment on such Public Policy Requirements to NESCOE, which comments shall be made publicly available on NESCOE’s and ISO-NE’s website, and/or through a stakeholder input session held in connection with one or more PAC meetings.

NESCOE shall make the final determination of which transmission needs driven by Public Policy Requirements, if any, ISO-NE will analyze in such Public Policy Study for potential solutions.

NESCOE will communicate its decision concerning what transmission needs driven by Public Policy Requirements ISO-NE will analyze in the Public Policy Study to ISO-NE and the PAC in writing and post such communication on its website. In this
communication, NESCOE will explain why ISO-NE will not evaluate other needs identified by stakeholders in the Public Policy Study.

To the extent that the states do not reach consensus in connection with a Public Policy Study scope or assumptions, NESCOE shall reach such determinations pursuant to NESCOE’s voting mechanism.

3. The PAC will provide input to NESCOE and ISO-NE on proposed study parameters and assumptions and on draft Public Policy Study results.

4. ISO-NE’s Public Policy Study conducted to analyze public policy requirements and/or public policy targets that NESCOE identifies shall include transmission project cost estimates.

5. NESCOE will review ISO-NE’s final Public Policy Study analysis, including the transmission project cost estimates.

6. After ISO-NE publishes the final Public Policy Study results, upon NESCOE’s written request, which shall be posted on NESCOE and ISO-NE’s websites, ISO-NE will perform one or more detailed transmission studies according to parameters and assumptions identified by NESCOE or developed with NESCOE approval (i.e., specific resource scenarios). NESCOE will discuss the scope and assumptions associated with such detailed transmission studies as identified by NESCOE with the PAC.

To the extent Public Policy Requirements and market efficiency or reliability needs may align, the detailed transmission studies may include analysis of potential solutions that may address market efficiency and/or reliability needs in addition to Public Policy Requirements. ISO-NE will make a preliminary determination about the extent to which a proposed transmission solution is needed for reliability and communicate that preliminary determination to the states and to PAC in writing.\(^1\) If Participating States

\(^1\) i.e., a transmission facility of a certain size that would meet reliability needs but could
agree that the portion of the transmission project ISO-NE determines is not needed for reliability meets the Participating States’ public policy needs, then the balance of the transmission project may be considered a public policy project for cost allocation purposes. Participating States are those states that determine that a transmission project meets their public policy objectives.

7. Because public policies, e.g., RPS, include cost-benefit considerations, a public policy project will require states to evaluate a proposed project’s costs and benefits. Such a project could only move forward if Participating States conclude that expected benefits outweigh expected costs. This evaluation requires mechanisms for cost control (e.g., firm contracts, risk sharing mechanisms), and assurance of delivery of benefits (e.g., RECs) to enable Participating States to approve and commit to a project. Power purchase agreements or other contractual arrangements will be needed to ensure that commitments are in place to address these and other key elements of public policy projects. Accordingly, the tariff will require that in order to be classified as a public policy project under the ISO tariff, any such contracts\(^3\) and/or inclusion of transmission costs associated with public policy projects\(^4\) be approved by the applicable state regulatory authority under the applicable law of each Participating State (including that there be a mechanism of appeal as appropriate within each Participating State, and/or avenue to resolve any dispute over state policy within the Participating State).

Upon approval of such agreement or inclusion of transmission costs associated with public policy projects by each applicable state regulatory authority, ISO-NE shall include public policy projects in the RSP and provide for the recovery of transmission and other applicable costs of such projects by means consistent with the decision or decisions of the applicable state regulatory authorities of the Participating States, which decisions may

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\(^3\) i.e., a power purchase agreement reflecting the “all-in” delivered cost of energy, capacity, RECS, and transmission or separate contracts for one or more of these.

\(^4\) For example, a separate agreement may provide for recovery of transmission costs through the tariff.
include approval of a cost allocation mechanism (to be determined) that is set forth in the regional tariff. The use of the term “regional tariff” does not imply that any customers in the region other than the Participating States would be subject to any charge.

The absence of approval by two or more states that a public policy project satisfies Public Policy Requirements as described above does not preclude any one or more states from determining that a project satisfies their states’ public policy objectives and, consistent with other elements of the ISO-NE tariff or otherwise permitted by law, assigning some or all of the costs of the project to the customers of the states making such a determination.
Order 1000
Consideration of Transmission Needs
Driven by Public Policy

New England Transmission Owners Presentation
to
NEPOOL Transmission Committee
May 1, 2012

Agenda

1. Introduction
   - Introduction, Discussions to Date
   - Order 1000 Requirements
   - TO Responsibilities
   - Examples of Stakeholder Interests
   - Positive Attributes of NESCOE Proposal
   - TO-Proposed Enhancements

2. Proposed Enhancements to NESCOE Proposal
   - Overview of Enhanced Proposal
   - Comparison to Current Reliability Process
   - Key Aspects of Enhanced Proposal

3. Details of Proposal, Step by Step

4. Some Open Issues, Adoption, Next Steps

Introduction, Discussions to Date

- The existing TOA requires coordination between the TOs and ISO on some issues, and between the TOs and NESCOE on others
- As part of this coordination, and as mentioned at the last TC meeting, the TOs have shared the proposed enhancements with the States, NESCOE, and ISO-NE; and received feedback.
- NEPOOL Counsel was invited to the discussions and attended.
- At today’s meeting, we are sharing the proposed enhancements with the broader stakeholder group … and hope to receive helpful feedback.
FERC Order 1000 Requirements

- Order 1000 requires the following changes to existing transmission planning and cost allocation processes:
  1. "Transmission needs driven by Public Policy Requirements" must be considered in regional and local transmission planning.
  2. The regional transmission plan must reflect a fair consideration of transmission facilities proposed by non-incumbents.
  3. Cost Allocation method must be defined and established for reliability, economic and public policy projects. Participant funding not allowed as default.
  4. Inter-regional Transmission Planning must be addressed.

- Transmission Providers (ISO-NE and New England TOs) must submit compliance filings with FERC on October 11, 2012 and for inter-regional planning, on April 11, 2013.

TO Responsibilities*

1. TOs along with ISOs have compliance filing obligations
2. TOs have authority/responsibilities related to costs, cost allocation (granted TOs by statute, subject to TOA)
3. Through the TOA, TOs have provided the ISO with certain authority to provide regional planning services, and the TOA has limitations on delegation of that authority
4. To comply with Order 1000, the revised planning process must satisfy open/transparent requirements of Order 890
5. Both the TOs and the ISO have to agree to changes to "right to build" provisions in the TOA subject to Mobile-Serra protection

Examples of Stakeholder Interests

<table>
<thead>
<tr>
<th>NESCOE/States</th>
<th>NEPOOL</th>
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<tbody>
<tr>
<td>• Authority to define public policy</td>
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<td>• Authority to define benefits for default cost allocation</td>
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<td>• Establish selection criteria</td>
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<td>• Authority over commitment to proposed projects</td>
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<td>• Lead role in generation/NTA solicitation*</td>
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<td>• Key role in cost allocation</td>
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<td>• Knowledge of total costs and customer impacts</td>
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<th>ISO-NE</th>
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<td>• Order 1000, 890 compliance</td>
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<td>• Opportunity for input/feedback on proposed processes</td>
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<td>• Full understanding of new planning process prior to filing</td>
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<td>• Stakeholder review of filings</td>
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<tr>
<td>• Accommodation of participation by qualified non-incumbents</td>
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<tr>
<td>• Opportunity for stakeholder input, once process is in use</td>
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<th>NE TOs</th>
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<td>• Maintaining separate, efficient reliability planning process</td>
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<tr>
<td>• Ensuring open, transparent, fair, efficient planning</td>
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<tr>
<td>• Transmission planning separate from, but synchronized with consideration of generation</td>
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<tr>
<td>• Order 1000, 890 compliance; while recognizing TOs filing obligations</td>
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TOs are looking for a collaborative and effective solution thru which their responsibilities can be satisfied.
TOs see many positive features in NESCOE Proposal

1. States are actively involved in the process, and are working jointly through NESCOE
2. States have an active role in defining key aspects of the process including defining public policy and selecting solutions
3. Recognizes that “needs” and “roles” must be defined for the process to work effectively
4. States commit to solutions and accept cost responsibility following study completion – if projects/solutions satisfy their criteria
5. Acknowledges that cost responsibility should be commensurate with perceived benefits
6. Recognizes need for Stakeholder involvement in the planning process, e.g. PRC participation

These positive attributes have influenced the TOs’ development of an enhanced, comprehensive proposal.

Proposed TO Enhancements:

1. Address ROFR, new entrant criteria for public policy process/projects
   – PTOs are prepared to waive Mobile-Sierra rights in conjunction with an agreement on a mutually acceptable public policy transmission planning process
2. Improve clarity and definition of core process components*
3. Preserve ISO-NE’s traditional role as an independent planning & process administrator
4. Maintain existing separate reliability planning process
5. Enable the efficient identification of preferred solutions ... while retaining States’/NESCOE’s authority over commitment to solution
6. Separate transmission planning from consideration of generation, while recognizing that synchronization is needed
7. Identify default cost allocation, with option for state override
8. Include progressive cost estimate accuracy / expectations (similar to current PP4)
9. Create a more comprehensive proposal

* Satisfaction of open and transparent principles of Order 890; Clear and early definition of public policy to be satisfied by regional planning process; Transparent development of a planning procedure for public policy; Earlier identification, publication, and commitment to assessment parameters and selection criteria for competing public policy projects/solutions.

TO Proposed Enhancements
Overview of Enhanced Proposal

1. Public Policy economic evaluation of generation & market alternative potential performed early
2. NESCO/States have decisional authority to:
   - Define: public policy requirements and the criteria to meet them
   - Define benefits for default cost allocation
   - Specify project selection criteria
   - Opt-out of the preferred solution where public policy will be satisfied via alternative means
   - Adopt an alternate cost allocation
3. Establish a new public policy asset type, planning procedure, default cost allocation** – distinct from reliability
4. ISO performs a public policy needs assessment
5. ISO has authority over planning-related decisions (base case, scenarios, etc.), similar to current reliability process
6. Submittal of solutions potentially open to incumbents and qualified non-incumbents
7. States make a commitment decision for preferred solution(s) - avoiding multiple iterations/studies by ISO NE and potential delays to reliability planning
8. Progressive cost estimate accuracy / expectations (similar to current PP4)

*Not states may evaluate solution specific alternate
Details of the Enhanced Process

Box 0: Create New Planning Procedure

Key Components:
1. ISO-NE, in coordination with TOs, writes a new public policy project planning procedure*
2. Addresses roles and responsibilities
   • i.e.: NESCOE/States, ISO-NE, project proponents, PAC stakeholders
3. Defines process including:
   • Quantification of public policy requirements
   • Needs assessment process**
   • Submittal of proposals, qualifications of sponsors
   • Quality of submittals, evaluation process, selection criteria
   • Cost level accuracy
   • Interface with 10 year RSP

Key Decision Maker(s):
• ISO-NE

Key Outputs:
• New ISO-NE Planning Procedure for PP
• Not filed at FERC

Focus of Enhancements:
• Reliability Planning – not disrupted
• Order 1000 – PP planning procedure established
• Order 890 – openness, transparency
• Fair, effective – rules of game identified in advance, neutral party administering

*Planning Procedure Periodically Updated
**Different than reliability

Box 1: Economic Assessment of Generation

Key Components:
1. Similar to economic studies performed under Attachment K
2. Enhanced to address public policy economic study needs of States/NESCOE
3. States/NESCOE provide guidance, e.g. evaluation of renewable generation type, quantity, location scenarios
4. Repeated each cycle

Key Decision Maker(s):
• States, NESCOE

Key Outputs:
• LMPs, Production Costs
• Other benefits, key findings
• Results used to enable execution of next box, i.e. public policy transmission requirements, assessment metrics, selection criteria

Focus of Enhancements:
• Similar to State/NESCOE proposal
Box 2: Define Public Policy Transmission Requirements, Assessment Metrics, Selection Criteria

**Key Components:**
1. Define new asset type:
   - New transmission project derived from public policy needs assessment
   - Not necessarily aligned with current PTF definitions
2. States/NESCO define state-controlled public policy transmission requirements; identify assessment metrics, selection criteria (including benefits).
3. ISO-NE writes Public Policy Requirements Guidance Paper*

**Key Decision Maker(s):**
- NESCOE

**Key Outputs:**
- PTF Requirements Guidance Paper, including:
  - PP to be addressed by process
  - Benefits (basis for default cost allocation)
  - Assessment Metrics for Needs Assessment
  - Selection Criteria for comparing proposals

**Focus of Enhancements:**
- Order 1000 – identification of PP, which is needed to identify benefits
- Order 890 - openness, transparency
- NESCOE/States substantive interests – in charge of critical decisions
- Fair, effective – establish “rules of the game” early

*PTF definitions utilized (See PPPTF or some category in published PPPTF)*

**Public Policy Guidance Paper periodically updated and used to satisfy paragraph 309 of Order 2000 which requires transmission providers to periodically review and update cost assumptions and needs assessment related to the transmission planning process.

Box 3: Establish Transmission Planning Base Case, Assumptions, Scenarios

**Key Components:**
1. ISO-NE defines transmission planning base case assumptions for subsequent Needs Assessment, e.g.:
   - Load growth
   - Topology
   - Contingencies modeling
2. ISO-NE, with input from the stakeholder process develops transmission planning scenarios and assumptions as required - normal PAC process, e.g.:
   - Fuel prices
   - Retirements
   - Generator Locations

**Key Decision Maker(s):**
- ISO-NE

**Key Outputs:**
- Transmission Planning Base Case Defined
- Fundamental Inputs, Assumptions Defined
- Required Scenarios, Sensitivities

**Focus of Enhancements:**
- Order 890 - openness, transparency
- Fair, effective
  - Rules of game identified in advance
  - Neutral party administration
  - Consistency across subsequent submittals

Box 4: Perform Transmission Needs Assessment, Identify Generic Requirement

**Key Components:**
1. ISO-NE performs transmission needs assessment, using:
   - NESCOE’s previously defined requirements
   - Transmission base case, assumptions, scenarios from prior step
2. Identify transmission needs driven by Public Policy, e.g.:
   - Generic/alternate source location
   - Constrained interfaces inhibiting delivery that must be addressed, by:
     - Bypassing, or
     - Expanding
3. Review with PAC, receive stakeholder feedback

**Key Decision Maker(s):**
- ISO-NE

**Key Outputs:**
- Source and delivery locations
- Constrained interfaces
- Generic solution(s)
- Notification: initiation of solution study phase

**Focus of Enhancements:**
- Order 890 - openness, transparency
- Fair, effective – rules of game identified in advance, neutral party administering
Box 5: Submittal, Identification of Possible Solutions, Apply Filter

Key Components:
1. Potentially open to incumbents and qualified non-incumbents.*
2. Multi-level filter
   - With Order 1000 exclusions
   - Qualification of sponsors (legal, financial, technical)
   - Quality of data submission
   - Initial high-level feasibility of project to satisfy public policy need

Key Decision Maker(s):
- ISO-NE

Key Outputs:
- Proposals that do not pass the filter
- Proposals that pass the filter
- Sponsors identified
- Cost estimate quality per PP4 (50%/+200%, "concept")

Focus of Enhancements:
- Order 1000 – PP planning procedure established, potential for ROFR to be addressed, proponent & project qualifications addressed
- Order 890 - openness, transparency
- Fair, effective – previously identified rules of game followed, neutral party administering

* ROFR for PP and qualification for non-incumbents addressed in more detail separately.

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Box 6: Evaluate Potential Solutions, Identify Preliminary Preferred Solution(s)

Key Components:
1. ISO-NE works with project sponsors, impacted TOs to evaluate submittals for their ability to satisfy PP needs defined in the Needs Assessment
2. ISO-NE applies PP Guidance Paper selection criteria to all submitted/accepted projects
3. Evaluate system impacts of the PP project on reliability: positive or negative
4. Identify preliminary preferred transmission solution
5. Determine if any planned reliability upgrades are made unnecessary by preliminary preferred PP project
6. Stakeholder/PAC review

Key Decision Maker(s):
- ISO-NE

Key Outputs:
- Preliminary Preferred Solution
- Preliminary adverse impact determination
- Reliability Displacement
- Cost estimate quality per PP4 (50%/+200%, "concept")

Focus of Enhancements:
- Order 1000 – PP planning procedure followed
- Order 890 - openness, transparency
- Fair, effective – previously identified rules of game followed, neutral party administering, projects/proponents treated consistently

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Box 7: More Rigorous Assessment, Select Preferred Solution, in RSP as Provisional Planned Project

Key Components:
1. Incorporate stakeholder input from prior step.
2. More detailed project information from proponent
3. Deeper technical analysis, e.g. stability, etc.
4. Assess "J.3.5-like" adverse impacts
5. Refine assessment of planned reliability upgrade made unnecessary
6. Refine cost estimates
7. ISO-NE identifies preferred transmission solution
8. Stakeholder/PAC review

Key Decision Maker(s):
- ISO-NE

Key Outputs:
- Preferred Solution Identified
- Reliability displacements known
- Adverse impacts considered, known
- In RSP as "Provisional Planned Public Policy Project"
- Cost estimate quality per PP4 (25%/+50%, "proposed")
Box 8: State Commitment Decision; Default Cost Allocation Unless Alternate Specified

Key Components:
1. States make commitment decision on ISO-NE identified preferred PP solution within predefined time period
2. Cost allocation determined: default (tbd*) or at state discretion alternative agreed to
3. For other than an all-states-in decision coupled with the default (tbd*) cost allocation, each state will make a finding public that includes:
   - Expected means of compliance with public policy requirements
   - Explanation of how cost responsibility is roughly commensurate with benefits

Key Decision Maker(s):
- States, NESCOE

Key Outputs:
- States Opt In or Out
- Cost allocation established
- State findings address expected means of compliance, alignment of benefits & costs
- Cost estimate quality per PP4 (25%/+50%, “proposed”)

Focus of Enhancements:
- Order 1000 – benefits based cost allocation
- Order 890 – openness, transparency
- Efficiency, Effectiveness – process has clear end, avoids unnecessary iterations

*Possible default cost allocations addressed in more detail separately.

Box 9: In the RSP as “Planned” Project, Rest of Process

Key Components:
1. I.3.9/PPA approval
   - No adverse impact
   - RC vote
2. In RSP as “Planned PP Project”*
3. Proceed thru remainder of planning process

Key Decision Maker(s):
- ISO-NE

Key Outputs:
- I.3.9/PPA outcome
- In RSP as Planned PP Project
- Cost estimate quality per PP4 (25%/+25%, “planned”)

Focus of Enhancements:
- NA

Some Open Issues, Adoption, Next Steps

*Possible default cost allocations addressed in more detail separately.
Some Open Issues

- The TOs have shared the proposed enhancements with the States, NESCOE, and ISO-NE; and received feedback.
- Various topics are still being discussed, for example:
  - State v. ISO-NE authority over some decisions
  - Form of State commitment to projects
  - Treatment of potential future federal policies
  - Cost certainty
  - Potential ability of States to truncate the process early
  - Cost recovery prior to truncation or State commitment to projects
  - Default cost allocation
  - Coordination with generation solicitation

Adoption of Enhanced Proposal is Feasible

1. Proposed tariff changes will be available for the next TC meeting
2. Draft of Qualifications for Non-Incumbents underway
3. New Planning Procedure needed
   - TOs ready to assist. Draft can be ready prior to filing
4. Proposed TOA changes have been identified (consistent with proposed tariff changes)
5. Sufficient time is available for changes to documents and required stakeholder process

Expected Next Steps:

1. Receive initial TC feedback today
2. Continued discussions
   - Continue dialogue with States/NESCOE and ISO
   - Open to meeting with any, all sectors
3. Tariff language and more TC feedback at next meeting
4. Achieve consensus
5. Share details of proposed changes with technical committees in June
6. Ready for final Technical Committee vote at joint meeting in August (or sooner if not deferred)
7. To NPC in September
8. File at FERC in October
# ISO NEW ENGLAND

**ORDER NO. 1000 COMPLIANCE ACTION ITEMS**
(excluding interregional coordination and interregional cost allocation)

<table>
<thead>
<tr>
<th>Order No. 1000 compliance requirement</th>
<th>Current status</th>
<th>Potential solutions</th>
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<tbody>
<tr>
<td><strong>I. SCOPE, TIMING, DEFINITIONAL AND COMPLIANCE FILING ISSUES</strong></td>
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<tr>
<td><strong>A. Timing of rule applicability:</strong> Specify in tariff what constitutes a “new transmission facility” to which the Order 1000 compliance revisions will apply (facility that is subject to evaluation or reevaluation within planning process after the effective date of the compliance filing). (PP 65, 162, 503)</td>
<td>No language currently in the Tariff.</td>
<td>Add tariff language that identifies projects not yet in the solutions phase on the effective date of the order no. 1000 rules as having any new rules apply.</td>
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<td><strong>B. Timing of rule applicability:</strong> Specify in tariff at what point a previously approved project is no longer subject to reevaluation and, as a result, whether it is subject to the Order 1000 compliance revisions. (P 65)</td>
<td>No language currently in the Tariff.</td>
<td>Same as A.</td>
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<td><strong>II. REGIONAL PLANNING PROCESS</strong></td>
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<td><strong>A. Identification of the preferred solution</strong> (PP 6, 11, 68, 148, 149)</td>
<td>Current tariff language provides for the solution study process, and presentations are made at PAC that narrow down and identify the preferred solution. However, the identification of the preferred solution would benefit from having a more formal process that clearly identifies the preferred solution for the region.</td>
<td>Add language to Attachment K that puts in place a process that more formally identifies the preferred solution arrived at through the solutions studies process.</td>
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*See also Order No. 1000 at PP 78-80, noting that while some areas use the regional transmission process to confirm simultaneous feasibility of transmission facilities found in local plans, ISOs and RTOs already undertake an analysis to identify the system needs in an efficient or cost effective manner.*

At P. 80: “In some transmission planning regions, a similar level of analysis is undertaken by public utility transmission providers at the regional level, resulting in a
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<td>regional plan that identifies those transmission facilities that are needed to meet the needs of stakeholders in the region. This occurs, for example, in each of the existing RTO and ISO regions, which, we note serve over two-thirds of the nation’s consumers.”</td>
<td>Economic Studies process can “consider” public policy requirements, but ISO is working with states and stakeholders on a process that would expand the studies process to develop transmission solutions that are supported by participating states.</td>
<td>NESCOE strawman being considered</td>
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<td>B. Public Policy Requirements: Add to the tariff a set of procedures for consideration of needs driven by Public Policy Requirements, and evaluation of potential solutions to meet those needs, in both local and regional transmission planning processes. (P 82, 111, 203, 205-06)</td>
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<td>NESCOE strawman being considered</td>
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<td>C. Public Policy Requirements: Add to the tariff a provision allowing stakeholders to have input in identifying PPR-driven transmission needs and offer proposals; if NESCOE will identify needs for which solutions will be evaluated, modify the tariff to so provide. (PP 207, 208-09, n. 189)</td>
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<td>NESCOE strawman being considered</td>
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<td>D. Public Policy Requirements: Add to the tariff a provision requiring a website posting explaining which PPR-driven transmission needs will be evaluated for potential solutions, and why other suggested needs will not be evaluated. (PP 209-10)</td>
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<td>NESCOE strawman being considered</td>
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<td>E. Public Policy Requirements: Specify in the tariff (consistent with Order 1000 cost allocation principles) how costs of solutions to PPR-driven needs will be allocated. (P 219)</td>
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<td>NESCOE strawman being considered</td>
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<td>III. ELIMINATION OF FEDERAL RIGHT OF FIRST REFUSAL</td>
<td>No changes if changes to the TOA are not sought by the PTOs. While a general finding was made in Order No. 1000, the issues of Mobile-Sierra contract rights in New England was expressly reserved and not ruled on in Order No. 1000, with the Commission directing that it would consider the specific issue when the compliance filing is made. Attachment K has been interpreted with the latitude for non-incumbents to construct and own facilities, e.g. the NEITC proposal for a submarine project. However, Order No. 1000, as a rule of general applicability across the country, directs the provision of an opportunity for non-incumbent TOs to build and own facilities in</td>
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<td>existing service territories (if allowed by state law and subject to Order No. 1000 exceptions concerning local transmission projects, upgrades to existing facilities, or right of way or eminent domain issues).</td>
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In New England, Solution Studies are the vehicle through which “proponents of regulated transmission solutions” offer projects. **Att. K § 4.2(b)** indicates that solution may differ from the solution proposed by a transmission owner (i.e., PTOs, OTOs MTOs). Projects are built by PTOs as/if designated by the ISO i/a/w TOA. **Att. K § 8.** These provisions, collectively, preserve an avenue for participation by nonincumbents. These provisions provide for the opportunity for any stakeholder, including non-incumbent transmission companies, to propose plans in the stakeholder process, but not to own and construct them in a competitive process. Such a right is currently precluded by a FERC-approved agreement between ISO-NE and the Transmission Owners.

TOA Schedule 3.09(a) language, and other provisions of the TOA, has been granted FERC protection under the *Mobile-Sierra* doctrine as part of the RTO formation and it would appear that the TOs must affirmatively agree to amend these provisions unless FERC makes a finding on an evidentiary record that the provision is not in the public interest, a difficult legal standard to meet.


Specifically, we will grant *Mobile-Sierra* protection, as requested, applicable to the following provisions of the Transmission Operating Agreement: sections 3.01, 3.09, 3.11, 3.13, 4.01(e), 6.07, 11.04 (a)–(d), and 11.05. *Id.* at P 74 (emphasis added).
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<td>Section 3.09 (transmission planning and expansion). [n50, see below] The Filing Parties assert that Mobile-Sierra protection is warranted, as it relates to section 3.09, because prospective investors in new transmission facilities demand certainty when it comes to the planning and construction process. NECPUC objects, arguing that the underlying rights and obligations addressed by section 3.09, in its entirety, should be addressed in the ISO-NE RTO OATT, not the Transmission Operating Agreement. <em>Id.</em> at P 77.</td>
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<td>We will grant Mobile-Sierra treatment, as requested by the Filing Parties. Section 3.09 provides direction to the Transmission Owners and the ISO-NE RTO to follow planning procedures contained in the ISO-NE RTO OATT. As such, this provision will have no adverse impact on third parties or the New England market. With respect to NECPUC’s request for rehearing, we deny NECPUC’s request to transfer section 3.09 and schedule 3.09(a) in their entirety to the OATT. *Section 3.09 and sections 6 and 7 of schedule 3.09(a) concern general references to previously adopted planning procedures and do not belong in the more detailed ISO-NE RTO OATT. <em>Id.</em> at P 78.</td>
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<td>Section 3.09 sets forth the rights and obligations of the Participating Transmission Owners and the ISO-NE RTO with respect to system planning and expansion. Specifically, section 3.09 and its corollary provision, schedule 3.09(a), delineate the Transmission Owners’ obligation to build in response to the regional</td>
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<td>needs as may be determined by the ISO-NE RTO. Section 3.09 also provides for the recovery of costs for such projects.  <em>Id.</em> at n.50.</td>
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<td>The initial order on the RTO-NE filing (106 FERC ¶ 61,280) had stated:</td>
<td></td>
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<tr>
<td></td>
<td>Accordingly, we will require the Filing Parties, in their compliance filing to submit revised tariff language reflecting the placement of Schedule 3.09(a) (with the exception of Sections 6 and 7) in the appropriate section of the RTO-NE OATT.  <em>Id.</em> at P 213.  [Note 128 explains: “Proposed Section 6 addresses the Transmission Owners rights and obligations to build and associated conditions including cost recovery. Proposed Section 7 addresses the Transmission Owner's obligations.”]</td>
<td></td>
</tr>
<tr>
<td></td>
<td>“We will reject, in part, intervenors requests that we modify or expand upon the Filing Parties’ proposal concerning a Transmission Owner's obligation to build. First, we disagree that this obligation can be influenced by (or avoided by) the Transmission Owner’s considerations of its own interests in a given project. In addition, we disagree that this obligation lacks flexibility, i.e., that it would preclude a Transmission Owner from working with another Transmission Owner or other entity to fulfill its obligation to build.  <em>Id.</em> at P 214.</td>
<td></td>
</tr>
<tr>
<td>B. Nonincumbent opportunity:</td>
<td>Give any “nonincumbent transmission developer” (defined as a transmission developer without a retail distribution service territory/footprint, or a transmission provider that proposes a project outside its territory/footprint) an opportunity comparable to an incumbent to allocate cost of facility through regional cost allocation</td>
<td>See corresponding discussion in III.A, above. This would apply to projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs.</td>
</tr>
<tr>
<td><strong>Order No. 1000 compliance requirement</strong></td>
<td><strong>Current status</strong></td>
<td><strong>Potential solutions</strong></td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>-------------------</td>
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</tr>
<tr>
<td>method(s). (PP 225, 316, 332, 335)</td>
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<td></td>
</tr>
<tr>
<td><strong>C. Broad eligibility of projects:</strong> Establish procedures to ensure that all projects are eligible to be considered for selection for cost allocation. (P 336)</td>
<td>See corresponding discussion in III.A., above. This would apply to projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs.</td>
<td></td>
</tr>
<tr>
<td><strong>D. Un-sponsored projects:</strong> If allow sponsor of transmission project selected in plan to use regional cost allocation method, also need to include a fair and not unduly discriminatory mechanism to grant to an incumbent or nonincumbents the right to use regional cost allocation for unsponsored transmission facilities selected in the plan. (P 336)</td>
<td>See corresponding discussion in III.A., above. This would apply to projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs.</td>
<td></td>
</tr>
<tr>
<td><strong>E. Qualification criteria:</strong> Develop (with stakeholder input) qualification criteria for determining an entity’s eligibility to propose a transmission project (whether an incumbent or nonincumbents); criteria must not be unduly discriminatory or preferential, and provide each potential developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate and maintain transmission facilities. (PP 7, 227, 323)</td>
<td>See corresponding discussion in III.A., above.</td>
<td>New entities may become PTOs under the current structure of the RTO, although new PTOs would not be able to compete with existing PTOs within existing systems – See III.A. New PTOs must become signatories to the TOA.</td>
</tr>
<tr>
<td><strong>F. Qualification criteria:</strong> Establish qualification criteria that are fair and not unreasonably stringent when applied to either incumbents or nonincumbents. (P 324)</td>
<td>See corresponding discussion in III.A. and III.E., above.</td>
<td></td>
</tr>
<tr>
<td><strong>G. Qualification criteria:</strong> Do not apply qualification criteria to an entity proposing a project for consideration if that entity does not intend to develop the project. (n. 304)</td>
<td>See corresponding discussion in III.A. and III.E., above.</td>
<td></td>
</tr>
<tr>
<td><strong>H. Qualification criteria:</strong> Allow for the possibility that an existing public utility transmission provider already satisfies criteria. (P 324)</td>
<td>See corresponding discussion in III.A. and III.E., above.</td>
<td></td>
</tr>
<tr>
<td><strong>I. Qualification criteria:</strong> Allow any developer the opportunity to remedy any deficiency. (P 324)</td>
<td>See corresponding discussion in III.A. and III.E., above.</td>
<td></td>
</tr>
<tr>
<td><strong>J. Notifications:</strong> Include procedures for timely notifying transmission developers of whether they satisfy qualification criteria and of opportunities to mitigate deficiencies. (P 324)</td>
<td>See corresponding discussion in III.A., above. These procedures would be developed for, and would apply to, projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs.</td>
<td></td>
</tr>
<tr>
<td><strong>K. Submission of proposals:</strong> Develop protocols for submission of</td>
<td>See corresponding discussion in III.A., above.</td>
<td></td>
</tr>
<tr>
<td>Order No. 1000 compliance requirement</td>
<td>Current status</td>
<td>Potential solutions</td>
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<tr>
<td>transmission proposals, including identification of: (i) info that must be submitted by developer in support of project; (ii) date by which such info must be submitted to be considered in a given transmission planning cycle. PP 7, 227, 325)</td>
<td>procedures would be developed for, and would apply to, projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs. Att. K § 4.2 re Solution Studies process set out the current provisions for the development of solutions. This could be enhanced to account for additional alternative proposals. There is no set planning cycle in New England, so deadlines for alternatives submissions for consideration in arriving at the preferred alternative would be keyed off a process point rather than a date.</td>
<td>Perhaps utilize an analogous approach to the RFAP process described in Att. K § 7(b)?</td>
</tr>
<tr>
<td><strong>L. Submission of proposals:</strong> Identify in sufficient detail the necessary information to be submitted: for example, could require relevant engineering studies and cost analyses; may request other reports or information, so long as fair and not so cumbersome as to effectively prohibit proposals, and not so relaxed as to allow relatively unsupported proposals. (P 326)</td>
<td>See corresponding discussion in III.A., above. These standards would be developed for, and would apply to, projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs.</td>
<td></td>
</tr>
<tr>
<td><strong>M. Evaluation process:</strong> Describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility. (PP 7, 227, 328)</td>
<td>See corresponding discussion in III.A., above.</td>
<td></td>
</tr>
<tr>
<td><strong>N. Evaluation process:</strong> Ensure that evaluation process culminates in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected; should build on existing processes (consistent with 890/890-A) that already set forth criteria for evaluating relative economics and effectiveness. (P 328)</td>
<td>See corresponding discussion in III.A., above.</td>
<td></td>
</tr>
<tr>
<td><strong>O. Evaluation process:</strong> Evaluate relative efficiency and cost-effectiveness of each solution. (n.307)</td>
<td>Subject to caveats in III.A., above, existing planning process would be compliant. See II.B discussion above. Alternatives from additional sources would be evaluated to identify the preferred alternative.</td>
<td></td>
</tr>
<tr>
<td><strong>P. Reevaluation:</strong> Describe in OATT the circumstances and procedures for reevaluating the plan to determine if development delays require evaluation of alternative solutions to ensure reliability needs or service obligations are met; incumbent transmission provider must have ability to propose solutions to implement within its retail distribution service territory/footprint enabling it to meet reliability needs or service obligations, and these should be evaluated in the regional process. (P 7, 263, 329)</td>
<td>Not addressed in OATT currently. See corresponding discussion in III.A., above. Would need to address this requirement in the evaluation process to be developed for projects subject to Schedule 3.09(a) of the TOA if Mobile-Sierra provisions of the TOA are amended by the PTOs.</td>
<td></td>
</tr>
<tr>
<td><strong>Q. Mobile-Sierra issues:</strong> Issues raised in NGrid’s comments re</td>
<td>Await input from PTOs.</td>
<td></td>
</tr>
<tr>
<td><strong>Order No. 1000 compliance requirement</strong></td>
<td><strong>Current status</strong></td>
<td><strong>Potential solutions</strong></td>
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<tr>
<td>Mobile-Sierra protections of Section 3.09 of the TOA are better addressed as part of ISO-NE compliance proceeding, where parties may provide additional information. (P 292)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>V. REGIONAL COST ALLOCATION</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>A. Core requirement:</strong> Include in OATT a method, or set of methods, for allocating costs (consistent with FERC-specified cost allocation principles) of new transmission facilities selected in plan for regional cost allocation. Method must apply to all transmission facilities of the type in question, and method must be determined in advance for each type of facility. Must address concerns that designation of transmission facility type can result in substantial delay because transmission facilities may serve multiple functions and benefits and beneficiaries may vary over time. (PP 9, 558, 560, 686, 690, 692)</td>
<td><strong>OATT Schedule 12</strong> applies to all RTUs, METUs. The New England process does not assign different parts of projects to different categories.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>B. Regional cost allocation principles:</strong> Include in OATT a method, or set of methods, for cost allocation that complies with the six regional cost allocation principles listed below. (PP 603. Principles: PP 622, 637, 646, 657, 668, 685)</td>
<td><strong>OATT Schedule 12</strong> allocates the cost of all “Regional Benefit Upgrades” as Pool-Supported PTF (subject to Schedule 12C Localized Cost Review). Regional Benefit Upgrades defined in Tariff § I.2.2 as a “Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU).” RTU and METU are defined in Tariff § I.2.2, as well.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>E. Regional cost allocation principles:</strong> With respect to every cost allocation method(s), OATT must allocate the entire prudently incurred cost of a transmission project (to prevent stranded costs). (P 640)</td>
<td><strong>OATT Schedule 12</strong> does not limit the costs of Regional Benefit Upgrades that are to be allocated thereunder. However, Localized Costs of an RBU are excluded from regional cost recovery per Schedule 12 § B.7 and Schedule 12C. Localized costs are fully allocated, in that case to a PTO-specific rate approved by FERC rather than to the RNS rate. If non-incumbent projects are utilized</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td>Order No. 1000 compliance requirement</td>
<td>Current status</td>
<td>Potential solutions</td>
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</tr>
<tr>
<td><strong>F. Regional cost allocation principle 1:</strong> The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements. <em>(P 622)</em></td>
<td>OATT Schedule 12 applies to all RTUs, METUs.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>G. Regional cost allocation principle 2:</strong> Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities. <em>(P 637)</em></td>
<td>OATT Schedule 12 applies to all RTUs, METUs.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>H. Regional cost allocation principle 3:</strong> If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation; threshold can be used to account for uncertainty in the calculation of benefits and costs.; threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves it. <em>(P 646)</em></td>
<td>OATT Schedule 12 applies to all RTUs, METUs. NESCOE strawman under review for public policy projects.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>I. Regional cost allocation principle 4:</strong> The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees</td>
<td>OATT Schedule 12 allocates costs for RTUs, METUs, solely within New England region. NESCOE strawman under review for public policy projects.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
</tbody>
</table>

1 Cost allocation principle 3 (for regional or interregional costs) does not require the use of a benefit to cost ratio. *(PP 647, 649)*
<table>
<thead>
<tr>
<th><strong>Order No. 1000 compliance requirement</strong></th>
<th><strong>Current status</strong></th>
<th><strong>Potential solutions</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>to assume a portion of those costs; planning process in the original region must identify consequences for other transmission planning regions, if the original region agrees to bear costs associated with upgrades in other region, then original region’s cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region. (P 657)</td>
<td>Cost allocation method for RTUs and METUs within OATT Schedule 12 is self-explanatory. OATT Att. N §§II.A and II.B provide significant detail as to the factors that go into identifying RTUs and METUs.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>J. Regional cost allocation principle 5:</strong> The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility. (P 668)</td>
<td>Cost allocation method for RTUs and METUs within OATT Schedule 12 is self-explanatory. The means by which RTUs and METUs are identified in the RSP Process is described in detail in OATT Att. N.</td>
<td>NESCOE strawman under review for public policy projects.</td>
</tr>
<tr>
<td><strong>K. Regional cost allocation principle 6:</strong> A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities; each method must be set out clearly and explained in detail in the compliance filing for this rule. (P 685)</td>
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</table>
Northeast Chapter EBA
Philadelphia, PA
June 6, 2012

Developing Transmission in the Northeast After Order 1000

Tom Welch
Chairman, Maine Public Utilities Commission

“Deference to Whom, and for What?”

- FERC has indicated that it will defer to a state determination of the existence and scope of “public policies” to be incorporated into transmission system planning.
  - What happens if states within a planning region do not agree?
  - Who decides whether there is a “state public policy?” I.e., is the test objective (there is a statute) or subjective (a state regulator decides)?
  - If the states, collectively or individually, conclude through their representatives (e.g. NESCOE) that there is no “public policy” project they wish to pursue, does that mean that there is not further obligation on the part of the regional planning entity or the transmission owners to include public policy in transmission system planning?
- Can the cost allocation for public policy transmission projects be determined by the states on a case by case basis, or must there be a “default” allocation that applies in the absence of agreement?
- Continuing areas of dispute:
  - States with development potential may favor objective standards for whether there is a relevant “public policy” and also favor a default cost allocation.
    - Rationale is to increase likelihood of a project emerging for which other states will bear some or most of the cost burden.
  - States with major public policy “needs” may favor absolute (subjective, case by case) state control over whether there is a public policy to be included in transmission planning and the cost allocation of any particular public policy project.
Rationale is that each state should retain control over whether any particular solution meets its public policy and cost objectives.

- Incumbent transmission owners favor whatever increases the chances of:
  - Additional projects emerging from the planning process
  - Full cost recovery (preferably the same as for reliability projects)

- Transmission owners and some states disagree about whether, absent state concurrence, the TOs have an independent obligation under Order 1000 to amend the tariff to include transmission system planning and associated cost allocation for public policy projects.

- Does FERC deference to the states extend to the question of whether there is any public policy for which planning must be done, or only to the question of which particular policies should be considered? And is there a difference if states can avoid having costs allocated to them by refusing to “opt in” to a public policy project?

- **Attachments:**
  - Snapshots of renewable development potential in New England
  - NESCOE Order 1000 Framework
  - Transmission Owner response to NESCOE Framework
  - ISO-NE Order 1000 compliance matrix
New England Renewable Energy Development Potential

Analysis Sponsored by NESCOE 2011

Tom Welch
EBA
June 6, 2012
New England Renewable Supply Mix Snapshot by State, Assuming No Transmission Additions

<table>
<thead>
<tr>
<th></th>
<th>Mix for 2016 (GWh/yr) Only generation costs considered</th>
<th>Mix for 2020 (GWh/yr) Only generation costs considered</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-shore</td>
<td>Off-shore</td>
</tr>
<tr>
<td>CT</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>MA</td>
<td>346</td>
<td>0</td>
</tr>
<tr>
<td>ME</td>
<td>5,391</td>
<td>0</td>
</tr>
<tr>
<td>NH</td>
<td>309</td>
<td>0</td>
</tr>
<tr>
<td>RI</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VT</td>
<td>883</td>
<td>0</td>
</tr>
<tr>
<td>New England total</td>
<td>6,929</td>
<td>0</td>
</tr>
<tr>
<td>NY</td>
<td>571</td>
<td>0</td>
</tr>
<tr>
<td>Grand total</td>
<td>7,500</td>
<td>0</td>
</tr>
</tbody>
</table>

- Resource mix based on generation costs for 15 year contract term, using baseline assumptions
- Developable NY resources in 2016 = 35% of NY resources developable by 2020
- NY imports constrained to 1000 MW
### New England Renewable Supply Mix Snapshot by State, Assuming Transmission Additions

<table>
<thead>
<tr>
<th>State</th>
<th>On-shore 2016 (GWh/yr)</th>
<th>Off-shore 2016</th>
<th>Total 2016 (GWh/yr)</th>
<th>On-shore 2020 (GWh/yr)</th>
<th>Off-shore 2020</th>
<th>Total 2020 (GWh/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>MA</td>
<td>360</td>
<td>720</td>
<td>1,080</td>
<td>986</td>
<td>2,683</td>
<td>3,669</td>
</tr>
<tr>
<td>ME</td>
<td>2,711</td>
<td>59</td>
<td>2,770</td>
<td>3,949</td>
<td>206</td>
<td>4,155</td>
</tr>
<tr>
<td>NH</td>
<td>280</td>
<td>0</td>
<td>280</td>
<td>396</td>
<td>0</td>
<td>396</td>
</tr>
<tr>
<td>RI</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>76</td>
<td>76</td>
</tr>
<tr>
<td>VT</td>
<td>883</td>
<td>0</td>
<td>883</td>
<td>1,467</td>
<td>0</td>
<td>1,467</td>
</tr>
<tr>
<td>NY</td>
<td>2,488</td>
<td>0</td>
<td>2,488</td>
<td>2,488</td>
<td>0</td>
<td>2,488</td>
</tr>
<tr>
<td>Grand total</td>
<td>6,721</td>
<td>779</td>
<td>7,500</td>
<td>9,286</td>
<td>2,964</td>
<td>12,250</td>
</tr>
</tbody>
</table>

- Resource mix based on costs for 15 year contract term, baseline assumptions
- Cost of on-shore generation in NH & ME (and VT) increased to reflect 50% of cost of required network upgrades
- On-shore generation in ME constrained to limits indicated by transmission analyses
- NY imports limited to 1000 MW
Where did EIPC come from?

- Idea born in early Spring, 2009
- Began through discussions between regional Planning Authorities
- Solidified in early Summer, 2009
- Current involvement by 25 Planning Authorities in Eastern Interconnection
- eipconline.com

Enter DOE ...

- DOE FOA0000068
- June 2009
- Topic A: Interconnection-Level Analysis and Planning for the Eastern Interconnection
- Topic B: Cooperation Among States on Electric Resource Planning and Priorities
- First-of-its-kind effort in the Eastern Interconnection
DOE Project – Primary Tasks

Status: Phase 2 – 3 Scenarios

“Business As Usual”
Continuation of existing conditions including load growth, existing Renewable Portfolio Standards (RPSs), and currently proposed environmental regulations. No new policies or regulations on carbon, no new RPS, no new EPA regulations. [F1S17]

“National RPS”
Meet 30% of the nation’s electricity requirements from renewable resources by 2030, achieved by utilizing a regional implementation strategy. [F6S10]

“Combined Federal Climate and Energy Policy”
Reduce economy-wide carbon emissions by 50% from 2005 levels in 2030 and 80% in 2050 combined with meeting 30% of the nation’s electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, demand response, distributed generation, smart grid and other low-carbon technologies; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy. [F8S7]

Status: Phase 2 – Transmission Analysis

- Phase 2 – To Be Completed in 2012
- The Study Year is 2030
  - Transmission additions required to meet reliability standards for three scenarios
  - Focus on 230kV and above
  - Consider HVAC and HVDC solutions
- Perform a Production Cost Run for Each System
- Estimate the Costs for Generation and Transmission Expansion
- Deliverable:
  Transmission option to support each of the resource scenarios. NOT a “Plan.”
Order 1000 References to Interconnection-Wide Planning (1)

Interregional Transmission Coordination (Paragraph 345)
- The Commission has decided there is a need for reform based upon the comments received, including those which criticize the “teams” in coordination of planning across the regions (Paragraph 369).
- FERC acknowledges the “positive developments” associated with the ARRA-funded interconnection-wide planning and reaffirms (Paragraph 371) that:
  - “While the ARRA-funded transmission planning initiatives represent a significant advancement in interconnection-wide transmission system analysis, they do not specifically provide for the ongoing coordination in the evaluation of interregional transmission facilities, which we conclude is necessary...”
  - “We encourage public utility transmission providers to continue their participation in these efforts and to explore opportunities to use the valuable information these efforts provide in their regional transmission planning and interregional transmission coordination efforts.”
  - “We reiterate our intent to build upon, and NOT interfere with, the ARRA-funded transmission planning initiatives in this Final Rule.”

Order 1000 References to Interconnection-Wide Planning (2a)

- Geographical Scope of Interregional Transmission Coordination (Paragraph 405)
- The Final Rule requires each public Transmission Provider to coordinate with its neighboring regions, within its interconnection (Paragraph 415).
- FERC will NOT require joint evaluation of a transmission project that is located in a single region. (Paragraph 416) However, Footnote #351 provided the following caveat:
  - “Moreover, the absence of such a requirement in this Final Rule does not affect any obligations public utility transmission providers may otherwise have to assess the effects of new transmission facilities on other systems, including but not limited to any other requirement of the OATT for interconnection studies, any requirement under the NERC reliability standards, and the requirements of Good Utility Practice.”

Order 1000 References to Interconnection-Wide Planning (2b)

- Geographical Scope of Interregional Transmission Coordination (Paragraph 405)
- The Commission encourages—but does not require multiregional or interconnection wide planning processes so as not to frustrate the progress being made under ARRA funding. FERC encourages parties participating in such ARRA-funded projects to explore how that might continue at the conclusion of the ARRA funding:
  - “To the extent that stakeholders in those planning initiatives wish to continue these activities at the conclusion of the ARRA-funded transmission planning initiatives, we encourage them to explore how existing regional transmission planning processes and interregional transmission coordination procedures implemented under Order No. 830 and this Final Rule could be enhanced to provide for such transmission planning activities.” (Paragraph 417)
  - The Commission “...decline to revisit how each transmission planning region defines itself...” (Paragraph 420)
Order 1000 References to Interconnection-Wide Planning (3)

- Interregional Cost Allocation Principle 4 (Paragraph 657)
  - "Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned inadvertently under this rule to a transmission planning region in which that transmission facility is not located. However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region, if the transmission providers in regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located." (Paragraph 657)

- In this context, the Commission reaffirms that it is not requiring either interconnection-wide planning or interconnection-wide cost allocation.
  - "The Commission is not requiring either interconnection-wide planning or interconnection-wide cost allocation." (Paragraph 660)

Conclusions

- Results of the ARRA funded projects will inform decisions on the future of interconnection-wide planning going forward
- Order 1000 encourages but does not require interconnection-wide planning
- Current interconnection-wide planning projects are a significant step and encouraged
- Fundamental basis for planning remains at the regional level with interregional coordination
- Regional compliance plans may reference interconnection-wide planning efforts

Questions and Discussion
Introduction – The Need to Expand PJM’s RTEP Protocol

Today, as part of its ongoing RTO responsibilities, PJM’s Regional Transmission Expansion Plan (RTEP) protocol comprises a process that considers the aggregate effects of many system trends: long-term growth in electricity use, generating plant retirements, broader generation development patterns – including the evolution of renewable resources – as well as demand response (DR) and energy efficiency (EE) programs.

This process culminates in one recommended plan – one RTEP – for the entire PJM footprint that is submitted to PJM’s independent Board of Managers (PJM Board) for consideration and approval. Under contractual agreement, the PJM Board’s approval then obligates transmission-owning utilities in PJM to build the facilities specified in the RTEP. This includes construction of new transmission lines and other facilities as well as upgrades to existing transmission assets.

PJM operates and plans the transmission system region-wide, as a whole, ignoring corporate and state boundaries when taking operational action or making planning decisions. By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM’s RTEP process helps focus on transmission upgrades that meet reliability criteria and increase economic efficiency more effectively.

PJM’s existing RTEP Protocol – codified in Schedule 6 of PJM’s Operating Agreement and described in detail in the PJM Manuals – has been applied by PJM so as to evaluate reliability and market efficiency driving transmission expansion plans today using bright-line triggers.

Since its inception in 1997 and until recently, PJM generally found that the magnitude of uncertainty regarding future system conditions was limited and that bright line tests used in the RTEP process could reasonably define the expected date of future reliability violations allowing PJM to plan new transmission facilities with minimal risk of fluctuating dates marking the expected onset of those violations.

That has changed in many respects.

PJM Board Direction to Consider New Decision-making Approaches

As PJM’s Board action placing the PATH and MAPP projects in abeyance strongly suggests, dramatic swings in economic forecasts, demand response, generation retirements and evolving public policies are adding greater uncertainty to PJM planning studies. PATH and MAPP abeyance action are but two more prominent, public examples. Others exist as well: removal of the Indian River – Salem segment from the MAPP project (earlier in its respective proceeding), removal of the Branchburg – Roseland – Hudson 500 kV line from RTEP and various reactive upgrade deferrals also provide witness to greater fluctuation in the onset and severity of identified reliability criteria violations.
Uncertainty about “at-risk” generation particularly in response to potential changes in environmental regulations, and growth in demand side resources are a source of new and greater uncertainty, complicating the analysis of future transmission needs.

The PJM Board has identified the Regional Planning Process Task Force’s (“RPPTF”) planning protocol review and enhancement efforts to be one of PJM’s most important stakeholder initiatives. The Board has asked PJM members to bring forth recommendations by Fall 2011 so that PJM might make appropriate filings and enact improvements in the planning process beginning in early 2012.

Order No. 1000 Compliance

Fundamentally, FERC’s July 21, 2011 Order No. 1000 addresses the need to establish a regional transmission planning process that incorporates a number of elements. In particular – and germane to the subject of this white paper – is a mandate (Order No. 1000 at ¶2) to include “procedures that provide for the consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations” that include “enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.”

Order 1000 goes on to state the following as well:

- “...we clarify that by considering transmission needs driven by Public Policy Requirements, we mean: (1) the identification of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions to meet those needs.” And,
- “...procedures must allow stakeholders an opportunity to provide input, and offer proposals regarding the transmission needs they believe are driven by Public Policy Requirements.”

In Order No. 1000 (at ¶223), the Commission stated that based on comments, the Commission acknowledges that “there is merit in allowing for flexible planning criteria to mitigate the possibility that bright line metrics may exclude certain transmission projects from long-term transmission planning. Therefore, Order No. 1000 (at ¶224) permits transmission providers to include in their compliance filing “revisions that they believe are necessary to implement flexible transmission planning criteria, including changes to existing bright line criteria.”

RPPTF efforts regarding RTEP protocol changes have paralleled the expected need to address such Order 1000 mandates by enhancing PJM’s existing RTEP Protocol. In fact, PJM anticipates making the bulk of the necessary FERC filings and manual changes to implement the RTEP Protocol changes proposed in this white paper well before an Order No. 1000 compliance filing in October 2012.

Brattle RPM Report

Likewise, the August 26, 2011 Brattle Group Report includes recommendations regarding additional transparency and sensitivity study information for the market, particularly regarding CETO and CETL values.1

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1 As part of load deliverability analysis, PJM first establishes a Capacity Emergency Transfer Objective (“CETO”) for each load deliverability area (“LDA”). CETO is the amount of energy that the transmission system must be capable of delivering to the LDA being tested in order to avoid shedding load due solely to the risk of its inability to import needed
load forecasting and other input parameters. Transparency comprises the exchange of information and mutual
dialog and continues to be the foundation for PJM's RTEP Protocol. And, as this white paper discusses,
transparency will be given even greater emphasis as the range of sensitivity and scenario analysis expands,
regardless of any decision-making framework that may or may not culminate in triggering transmission
expansion.

**Taking the next step...**

Clearly, the landscape in which PJM conducts planning has changed. This white paper sets forth two
proposed expansions to PJM's existing RTEP protocol:

1. Expanded scenario planning and communications elements of the existing RTEP protocol, comprising
what will be known here forward as the “FYI Process” and,

2. Expanded RTEP decision-making framework elements that rely on the foundation of analysis and
stakeholder interaction that flow from the FYI Process.

This expanded decision-making framework provides three new approaches or avenues through which new
transmission can be incorporated into PJM's RTEP. These new approaches offer opportunities to justify
transmission expansion need beyond that which already exists today in terms of reliability and market
efficiency.

PJM is enhancing its RTEP decision-making framework, driven by a confluence of growing trends. While
reliability and market efficiency requirements will continue to be a fundamental part of the RTEP protocol,
decision-making must be expanded to address these trends: both new and emerging factors as well as
additional variability in factors that have ‘traditionally’ driven need for system expansion, to date.

PJM must move to a more organic approach in the decision-making process that allows triggering RTEP
upgrades in light of public policy drivers, such as RPS requirements, EPA regulations, load impacts of DR and
EE, at-risk generation, and others. Importantly, reliability may remain at the core of most projects, but
changing assumptions will cause other benefits to be lost if planning process tests look only at reliability
triggers. Also, by the time assumptions potentially swing back, sufficient lead-time may not exist to
implement a robust transmission solution in a timely fashion.

This White Paper describes challenges the RTEP protocol faces today and proposes decision-making
framework solutions:

- **Section I, “Existing RTEP Protocol Decision Making Framework”** describes today’s bright line reliability
  and market efficiency driven decision-making process, providing the backdrop against which proposed
  RTEP protocol changes are to be made.

- **Section II, “Providing Information to Constituencies and Stakeholders”** discusses the "FYI" process
  as an expansion of today’s study, communications and stakeholder elements of the existing PJM RTEP
  protocol, per Schedule 6 of the PJM Operating Agreement.

capacity assistance during a capacity emergency. The Capacity Emergency Transfer Limit (“CETL) is determined from
the actual Load Deliverability power flow analysis and expresses the maximum MW that an LDA can import under
specified peak load test conditions.
• **Section III**, “Implementing New Decision-making Approaches” describes how three new decision making frameworks would work:
  - State Agreement Approach
  - Critical Mass Approach
  - Proactive Approach

• **Section IV**, “Next Steps” addresses PJM Operating Agreement and Manual changes needed to implement the expanded RTEP protocol concepts proposals herein.

Firstly, this white paper provides a discussion of where PJM is today: the *Existing RTEP Protocol Decision Making Framework.*
I. Existing RTEP Protocol Decision Making Framework

PJM is required to apply NERC Reliability Standards in its planning process. The NERC Reliability Standards specify a wide range of reliability tests that must be applied over both near-term (years one to five) and long-term (years six to ten) planning horizons. Violations of these standards in either the near-term or long-term planning horizons can form the basis for PJM-directed baseline transmission solutions. All reliability criteria testing procedures employed in the development of the RTEP include detailed assumptions regarding load levels, transfer levels and generation patterns. The tests are referred to as “bright line” because, based on these documented procedures and assumptions, violations are identified when limits are exceeded even by one MW.

**Exhibit 1: RTEP Protocol Process Flow Diagram**

Baseline Reliability Upgrades

PJM’s baseline reliability assessments identify areas where the electric power system, as forecasted over a specific time, would not be in compliance with NERC Reliability Standards\(^2\). These baseline assessments lead

\(^2\) NERC reliability standards in the context of PJM’s planning process are discussed in PJM Manual 14B, accessible from PJM’s web site via the following URL link: [http://pjm.com/~/media/documents/manuals/m14b.ashx](http://pjm.com/~/media/documents/manuals/m14b.ashx)
to recommendations for enhancement plans, referred to as baseline transmission network upgrades, to ensure compliance with those standards, as highlighted in the Exhibit 1 process flow diagram, above. In essence, the construction of baseline transmission network upgrades is required to ensure that the PJM system remains in compliance with NERC Reliability Standards. The baseline transmission network, including these upgrades, then serves as the basis for the analysis of subsequent requests for transmission service and interconnection.

In order to complete these studies, PJM models expected future system conditions. Power flow case development requires PJM to employ a number of forecasts and assumptions about the future state of the system. For example, PJM must apply initial assumptions regarding load forecasts, development or deactivation of generation, transmission topology, demand response resources and power transfer levels between areas of the grid. Pursuant to the PJM Operating Agreement, PJM documents all assumptions, which are thoroughly vetted through the PJM stakeholder process.

PJM applies a number of tests including those for load deliverability and generator deliverability to determine compliance with NERC Reliability Standards. If PJM identifies violations of NERC Reliability Standards, then it is required to develop and implement solutions to mitigate those violations. These solutions must include a schedule for implementation, including expected in-service dates, considering the lead times involved for the identified solutions. Subsequent annual assessments review the continuing need for the identified system facilities.

This will not change under the proposals put forth in this white paper, remaining a key part of the foundational "FYI Process" described in Section II, below.

**PJM’s FERC-Defined Transmission Expansion Planning Role**

As an RTO, PJM has a defined role in the electric industry, with specific obligations relating to the transmission system, wholesale electric markets, and the end-use of electricity. PJM’s primary transmission-related responsibility is to ensure the reliability of the bulk power transmission system. Although PJM has a number of important tools at its disposal – including the ability to direct transmission owners to construct transmission projects – its powers are not plenary. Because FERC has determined that the wholesale energy markets should be competitive and based on economic conditions, rather than regulatory mandates, PJM is not able to direct or otherwise control the siting, capacity, or timing of new generation on the grid. Similarly, because energy end-use is a matter of state regulation, PJM is not able to compel or otherwise control the design and implementation of DSM/EE efforts that might, if properly placed and of sufficient dimension, delay or defer the need for transmission reinforcements. In short, based on the authorization it has received from FERC, PJM can only direct the reinforcement of transmission facilities to address reliability violations, either through the modification of existing transmission facilities (which PJM quite frequently directs) or the construction of new transmission facilities.

Because the consequences of reliability criteria violations can be severe in terms of their impacts on customers and the economy, PJM’s first and foremost mandate is to maintain system reliability. That being said, however, PJM’s planning process is expressly designed to be responsive to solutions developed through the generation and end-use marketplaces, in large part through RPM auction activity. This will not change either and, in fact, a number of the changes discussed in Section II, below, are designed to enhance the information flow underlying the RTEP and improve opportunities for market-driven solutions to grid issues.
Market Efficiency Driven Upgrades

PJM’s Regional Transmission Expansion Plan (RTEP) Process includes market efficiency analysis, the goal of which is to accomplish the following objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.
2. Identify new transmission upgrades that may result in economic benefits.
3. Identify economic benefits associated with modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints.

Such upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues. For example, PJM’s 2010 market efficiency analysis evaluated several upgrades for inclusion in the PJM RTEP based on the economic benefits they are projected to provide. These economic upgrades have the potential to relieve congestion at a number of locations throughout the PJM footprint.

Essentially, economic benefits of transmission upgrades – from the perspective of mitigating congestion - are determined by comparing results of production cost simulations with and without defined transmission upgrades. These simulations consider a number of key economic parameters including fuel costs, emissions costs, future generation scenarios, load forecasts and Demand Resource projections.

These studies, and the decision process which drives their specific inclusion in the RTEP, are not currently projected to change.

Stakeholder Proposed Upgrades

As an extension of the market efficiency component of the RTEP protocol, any Transmission Expansion Advisory Committee (TEAC) member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit alternative proposals for evaluation under the market efficiency analysis at any time.

Indeed, this very concept – the ability for a market participant to propose projects - plays a key role in the FYI Process going forward, and in fact would be the means by which state-backed transmission proposals would be considered.

Today’s Decision Process Limitations

PJM’s existing RTEP protocol – codified in Schedule 6 of the PJM Operating Agreement and described in detail in the PJM Manuals – defines the specific baseline reliability and market efficiency bright line tests governing transmission expansion. Over the past several years, however, those highly prescriptive provisions have encountered a reality far different from the one in which they were developed. Today, uncertainty around time-to-construct and the onset of criteria violations are not characterized by definitive ‘step functions’ in the context of the reliability risk they may introduce. Rather, as Exhibit 2 depicts, this uncertainty is more aptly represented by curves, the area under the overlapping area of which represents risk to customers.
Time to Construct

As Exhibit 2 depicts, time-to-construct and criteria violation onset are more aptly represented by curves the extent of which, represented by the highlighted area, comprises a reliability risk to PJM and the customers PJM serves.

From a timeline perspective, if construction of an upgrade cannot be completed by the time RTEP-identified criteria violations are expected to occur, then a situation may arise in which Reliability Must Run (RMR) generation and operational solutions such as out-of-merit generation dispatch may be required to control growing congestion costs and reliability risk. And, while project management options may exist to reduce construction times – additional crews, overtime, etc. – RMR and operational steps may yet still be required if a transmission facility is not completed in time. Those actions, however, impose costs associated with out-of-merit generation redispachment and include the potential threat of operator action up to and including customer service disruption.

Exhibit 2: Transmission Expansion Uncertainty and Risk

Recent experience with the Susquehanna – Roseland 500 kV project provides a case-in-point in which construction activities cannot begin until all necessary federal and state regulatory approvals are in place. Such regulatory delays themselves are pushing construction completion beyond the required in-service date for the facility to avoid identified reliability criteria violations.

On the other hand, transmission owners may be unable to secure regulatory approvals if need for a project is to too far into the future compared to expected construction completion.

Onset of Criteria Violations

Again, uncertainty around the onset of reliability criteria violations is not characterized by a definitive ‘step function.’ As Exhibit 2 shows, violations may occur earlier or later than expected. This arises from the
volatility of input parameters that shift violations in time. And, now, myriad other factors - including at-risk generation, RPS generation, increasing reliance on DR and EE and other state public policy initiatives have begun to introduce additional reliability risk “under the uncertainty curve.” Existing baseline reliability and market efficiency triggers simply are not sufficiently flexible to consider all these emerging factors.

Emergence of "Whip-saw" Effect on RTEP Decision-making

Planning is a dynamic process and system conditions change over time. Changing circumstances may result in the need to adjust the assumptions used in planning studies and to re-evaluate decisions made as a result of previous planning analyses.

Most recently, in the case of the PATH project, the 2011 Load Forecast projected slower rates of load growth for the near term than had been seen in earlier forecasts. Changing load forecasts are not the only levers that affect when violations of NERC Reliability Standards appear. Changes in generation additions and retirements, particularly if the plants are electrically proximate to constrained facilities, have the potential to affect the appearance of reliability violations in dramatic ways, as does increasing reliance on demand response and energy efficiency programs. These changes also can be very unpredictable and arise very quickly.

Backbone transmission projects, especially those as complex as the PATH and MAPP projects cannot be effectively planned, funded, approved, and constructed if they are continually taken on and off the table – the “whip-saw” effect - based on updated data. Once a project is shelved, it cannot simply be put back on track when changing system conditions, revised load forecasts (for example) and other factors, which may have supported project delays a few months earlier, suddenly turn in the other direction.

The complexity does not end there. Regional expansion planning drivers can cut both ways. Any one individual factor may contribute to the need for one transmission expansion upgrade and simultaneously mitigate the need for another. This is particularly true with the impacts of clustered generation additions. Location is everything. New generation at one interconnection point may increase cross-system power transfers while another may back them off thereby helping to mitigate congestion.

Taking the next step

So, how do we put in place a planning process decision-making structure that considers all this, and more?

Over the past year PJM staff and stakeholders have undertaken a comprehensive review of various ways to improve the Regional Transmission Expansion Planning (RTEP) process and related generator interconnection process. This effort is driven by many factors, but perhaps the most important driver is the changing planning landscape given impacts of the economy, new environmental regulations and the need to address events that could affect the timing of reliability projects. By expanding the criteria for projects and allowing for a broader range of assumptions within scenario planning, the PJM system will be better prepared to manage a range of uncertainties.

Through the Regional Planning Process Task Force (RPPTF), PJM and stakeholders have discussed how the planning process can consider at-risk generation, incorporate public policies enacted by state and federal entities, enhance the integration of renewable resources and account better for the growth of demand response and energy efficiency programs. The RPPTF also has reviewed how PJM can consider and designate
alternative transmission proposals to an entity other than a local incumbent transmission owner. All of these goals point toward a more robust planning process.

The first step, discussed below, is to expand the communications and stakeholder interaction elements of the existing PJM RTEP protocol, per Schedule 6 of the PJM Operating Agreement, to provide information to stakeholders – both market participants and states alike - within the PJM footprint.
II. Providing Information to Constituencies and Stakeholders

The concept of Providing Information to Constituencies and Stakeholders continues to evolve as the "For-Your-Information Process" or "FYI Process" - shown in Exhibit 3, below. The FYI Process is not a new decision making approach. Rather, "FYI" puts a name to the analytical and communications pieces of the RTEP protocol in place today, per Operating Agreement Schedule 6, and expands them.

Exhibit 3 – FYI Process and Expansion Plan Decision-Making Framework

The FYI process provides the foundation for the expanded decision-making framework, expanding the RTEP protocol analyses beyond the existing reliability and market efficiency triggers driving transmission expansion upgrades. Each would remain, though, as a test which could drive new transmission expansion, and/or provide a piece of the support for new transmission, as Exhibit 3 shows.

FYI Process Philosophy

In many respects, PJM has already begun the transition to the FYI Process. In 2010, PJM complemented its traditional bright-line tests with sensitivity analyses that incorporate a number of factors not typically taken into account under those tests, including the potential impact of state renewable portfolio standards, demand response and energy efficiency efforts, and “at-risk” generation.
The FYI process would provide stakeholders – market participants and states, alike – even greater up-front opportunity to provide input on modeling assumptions and analytical scenarios, and post-analysis opportunity to review and discuss study results. The analysis component of the RTEP protocol will thus also comprise additional extensive scenario studies, per stakeholder input.

Overall, the FYI process will afford PJM the opportunity to publish and communicate a wide range of results, the goal of which is to send signals to stakeholders. Doing so will allow market participants and states to make their own respective informed decisions on what solution opportunities to pursue. However, while the results PJM produces could include performance of various solution options, no RTEP action would be taken by PJM with respect to such solutions within the context of the FYI process. The goal of the FYI process is to provide information that informs both stakeholders and the RTEP decision-making elements that comprise the “Decision Framework” aspect of Exhibit 3. Exhibit 3-B, below, highlights the four main components of the “FYI Process”

**Exhibit 3-B – FYI Process**

How the FYI Process would work...

Here again, "FYI" puts a name to the analytical and communications dimensions of the RTEP protocol in place today, per Operating Agreement Schedule 6, and expands on them within the context of a 24-month timeline for backbone transmission (primarily 345 kV and above) and two consecutive 12 month timelines for transmission analysis below 345 kV:

- A 24-month time line would focus on backbone transmission analysis at 345 kV and above, as well as some 230 kV facilities serving a more regional function. Analysis would examine all needs and drivers related to the backbone transmission system and serve as an input to the decision framework elements described later in this document. Two consecutive 12 month time lines which would would focus on transmission analysis of facilities below 345 kV, as well as some 345 KV facilities serving
more localized needs. As with the backbone system, analysis would examine all needs and drivers and serve as an input to the decision framework elements described later in this document, but with an expectation that solutions would likely be able to be implemented with shorter lead times than required for the backbone system.

**Exhibit 4-A and Exhibit 4-B** both show the same proposed 24-month planning process cycle, integrating reliability and market efficiency analysis with information transparency, stakeholder input and review and PJM Board of Manager approvals. Note that activities shown on these diagrams and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

**Exhibit 4-A** and **Exhibit 4-B** are differentiated in that each shows how the two consecutive 12-month under-345 kV planning cycles would each overlay with the 24 month backbone cycle. Note that while the 24-month cycle refers to 345 kV facilities and above, the focus is on facilities that serve a primarily regional function, including some 230 kV and 345 kV facilities. Similarly, the 12-month cycle focuses on facilities that serve a primarily local function, including some 230 kV and 345 kV facilities. **Exhibit 4-A** shows the integration of the “Year 0” 12-month cycle within the 24 month backbone cycle. **Exhibit 4-B** shows the integration of the “Year 1” 12-month cycle within the same 24-month backbone cycle.

**Exhibit 4-1: FYI Process 24-month Planning Cycle overlay with “Year 0” 12-month cycle**

![Diagram showing 24-month Planning Cycle overlay with “Year 0” 12-month cycle](image-url)
Basic Conceptual Process Description

1. The first step in the FYI process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at TEAC, Subregional RTEP and State RTEP Committee meetings. These meetings also provide stakeholders the opportunity to propose scenario analyses for the coming 24-month study cycle, for example:
   a. Resource Scenarios -- e.g., At-Risk, New Generation, RPS, Marcellus Shale
   b. Load Scenarios -- e.g. High or low economic growth, scope of possible DR and EE solutions
   c. Other scenarios proposed by stakeholders

2. A series of power-flow base cases are then developed based on the assumptions. The yearly series of cases will include the latest information and assumptions available regarding load, resources and transmission topology. A new 5-year base case is developed for near-term analysis. Base cases for retool analyses of years closer than 5-years will be developed as necessary.

3. In addition to near-term base cases additional power-flow base cases will be developed for long-term planning. These long-term cases are used to evaluate the need for more significant projects requiring longer development lead-times. The long-term base case developed at the start of each 24-month planning cycle is based on the system conditions that are expected to exist in Year 8, as shown in Exhibits 4-A and 4-B. This 8-year-out base case will also be updated and retooled at the start of the second year
4. The scope of the near-term analysis completed as part of each 12-month planning cycle will include an exhaustive review of applicable reliability planning criteria on all Bulk Electric System (BES) facilities (i.e., at 100 kV or higher). PJM performs this near-term analysis on a 5-year-out base case. Retool analyses of previous near-term assessments are also completed, as required. Any identified criteria violations are reviewed with stakeholders throughout the FYI process.

5. Ultimately, solutions to address the criteria violations are developed, reviewed with the TEAC, Sub-regional RTEP and State RTEP Committee and, as applicable, and submitted to the PJM Board of Managers for approval. From an interconnection request perspective, through the FYI process, a 5-year near-term baseline system model without any criteria violations is developed for subsequent queue studies.

6. Longer-term planning is also completed as part of the development of the RTEP to identify solutions to planning criteria violations that require longer lead times to implement. As part of the FYI process 24-month planning cycle, PJM will initially develop an 8-year-out base case to evaluate planning criteria for the longer-term planning horizon. Long term criteria analysis is completed on this base case during the first year of the 24-month cycle.

7. A combination of full AC power flow simulation and linear analysis will be used to determine the loading on facilities in years 8 through 15. All reliability criteria violations and proposed solutions will be developed by stakeholders and PJM during the first year of the 24-month planning cycle.

8. As shown in Exhibit 5, during the second year of the 24-month planning cycle, the base case used for the long-term analysis during “Year 0” (i.e., the year 7 case) will be updated to reflect the latest assumptions about load, generation, DR, EE, and transmission topology.

Exhibit 5: FYI Process 24-month Base Case Development Process
9. Long term analysis is completed on this base case during the “Year 1” of the 24-month cycle. A combination of full AC power flow simulation coupled with linear analysis is again used again to determine the loading on facilities for years 7 through 15. Potential violations identified during “Year 0” are validated and the proposed solutions to address those violations are refined during the “Year 1” of the 24-month planning cycle.

10. An independent consultant may be used to develop an independent cost estimate and evaluate the feasibility of actually building proposed solutions. Results from these long-term analyses, including potential violations and their solutions, are reviewed with the TEAC, Subregional RTEP Committees and State RTEP Committee throughout the 24-month planning cycle of the FYI process.

11. Ultimately, any required long-lead time solutions identified through this process are presented to the PJM Board of Managers for approval. Subsequently, PJM will post Board presentation materials (redacted for any confidential content for Board consideration only).

Considering Public Policy and other Factors

FYI scenario studies will provide information regarding the impact that changing assumptions have to threaten reliability if previously unexamined factors are not evaluated. RTEPP changes are needed to facilitate PJM’s ability to manage more effectively the recent “whip-sawing” of project in-service dates and address broader public policy and other factors that change modeling assumptions.

Public Policy Drivers

Over the past several years, an increasing focus by federal and state governments on climate change, energy independence and other policy areas continues to make clear the critical role of the transmission system. And, while the existence of violations of NERC Reliability Standards is the basis for PJM’s determination of need, construction of major transmission infrastructure will likely be necessary to support the achievement of public policy goals.

These policies range from promoting renewable generating resources (such as wind and solar), DR and EE, to requiring environmental compliance that will affect PJM’s fossil generating fleet (tagged by PJM as “at-risk” generation).

Integrating wind resources, often distant from the population centers that will use the electricity they produce presents a unique set of challenges to planning new transmission. Moreover, PJM’s RTEP process continues to address the need to strengthen the nation’s electrical grid to accommodate the retirement of generating resources not able to meet environmental regulations, including those regarding NOx, SOx, CO2 emissions and water quality. Whether taken individually, or addressing their collective impact all such policy decisions necessarily impact transmission planning decisions and may require action in some instances to ensure reliability.
RPS Standards

An increasing focus by federal and state governments on climate change and energy independence continues to make clear the critical role of the transmission system. An important element of these policies is greater use of renewable resources, primarily wind. In PJM's footprint, a number of state jurisdictions have adopted renewable portfolio standards (RPS), requiring electricity suppliers to purchase specified amounts of renewable energy as part of their supply portfolio. RPS goals – in state jurisdictions where they are mandated - range from 10 percent to 25 percent. Integrating wind resources is raising significant transmission public policy issues which ask the following questions:

- What are the impacts on reliability and economic efficiency across multiple regions?
- How much transmission should be built?
- Where that transmission should be built?
- Who should pay for that new transmission capability?

Through its involvement in the system interconnection process and its operation of the transmission system, PJM tracks closely the existing and proposed generation projects in the PJM footprint. PJM experience in the RTEP process has shown that the inclusion or exclusion of significant generation resources, particularly those in electrical proximity to constrained transmission facilities, can have a marked impact on the occurrence and timing of projected violations of NERC Reliability Standards.

"At-risk" Generation

Likewise, existing generating facilities frequently must weigh the costs of increased investment to address environmental compliance issues and construct other needed improvements against anticipated revenues in PJM’s energy, capacity, and ancillary services markets and under existing power purchase agreements; decisions on an existing facility’s economic viability can influence whether it will continue to operate.

At-risk generators face the real possibility of deactivation given the economic impacts of such factors as increasing operating costs associated with unit age (some more than 40 years old) and changing environmental public policy, particularly with regard to carbon emissions, NO\textsubscript{X}, SO\textsubscript{X} and water quality.

The need to comply with evolving federal and state environmental restrictions affects a fossil generator’s ability to recover sufficient revenue to remain economically viable. A main source of revenue is from the capacity market. Whether or not a unit has cleared an RPM auction maybe an indicator of the plant’s future viability, particularly if compared to its competitors more efficient plants.

Costs related to a range of factors drive the ability of a plant to reap consistent revenue streams from PJM’s energy, capacity and ancillary service markets. In addition to the risk from public policy and aging units, a potential at-risk indicator is a plant’s inability to clear an RPM capacity auction given its costs compared to other resources offered into the auction:

- other more efficient plants
- demand resources and
energy efficiency programs, for example.

From a generator’s own market participation perspective, a generator must weigh the additional revenue stream that an RPM auction-cleared generating resource could provide against the risk that the same generator may not clear an auction given the potential higher auction bid required to factor in higher capital costs or operating and maintenance costs due to tighter environmental regulations.

Communications and Information Exchange throughout the FYI Process

Activities of the TEAC, Sub-regional RTEP Committees and new State RTEP Committee will provide the primary forums for the ongoing exchange of ideas including discussion of input assumptions, suggested scenarios studies review of PJM study results. Under an expanded FYI process, study results would inform the market participants and states alike so each can choose whether to make respective resource investment decisions based on the information provided.

The activities of these committees are at the core of PJM-stakeholder FYI process interactions regarding the following:

- Power flow case modeling parameter assumptions
- Suggestions for scenario analyses
- Periodic review of PJM study results including the identification of reliability criteria violations and market efficiency results;
- Ongoing discussions of proposed solutions and results of requested sensitivity studies regarding them

The broad range of stakeholders which these committees comprise is expected to foster a wide range of opinions, comments and advice on RTEP development, recommendations for additional analysis and, ultimately, advice on proposals for PJM Board approval.

However, this is not to say that these committees will necessarily require extensive discussion of each and every solution driven by PJM study results. Simple, rational practicality suggests otherwise. In fact, given recent history, many solutions proposed by PJM as part of the FYI process are not expected to require protracted discussion. For example, if a simple wave trap is sufficient to solve a 500 kV reliability criteria violation, it is not expected that significant debate of alternative solutions will be necessary.

PJM anticipates that most debate and ongoing discussion will focus on reliability criteria violations and scenario analysis results that suggest larger-scale backbone based solutions.

State RTEP Committee

Decision making under the State Agreement Approach necessarily depends upon effective two-way information flow and dialog within the context of the FYI process. This includes providing up-front input on assumptions and scenario analysis as well as coordinated analysis and review of FYI process study and scenario results and would provide high level consideration of multiple drivers and solution alternatives
PJM anticipates that a State RTEP Committee would be formed and integrated into the FYI Process. In the course of the discussion and evaluation of FYI Process Scenario analyses, a state (or states) may decide that it would be beneficial to evaluate a specific transmission solution and may request PJM to conduct both reliability studies and cost-benefit analysis of same. The activities of the State RTEP Committee will occur in parallel with FYI Process TEAC activities and broader FYI Process study activities. The purpose of the committee is to facilitate dialog between PJM and the states to enhance understanding of impacts of various transmission need drivers. The committee does not make decisions about what transmission should be in the RTEP; it is purely an information transparency vehicle.

The interaction between the states and PJM in this committee may also include targeted discussion of study results and specific solution alternatives in addition to ones that PJM itself may put forward via TEAC in order to address one or more possible transmission expansion drivers.

The information flow via committee activities may allow states to determine whether they may wish to support a project to accomplish their policy objectives. This information flow may also provide states input that they can use as they shape their policy objectives. Should a state or group of states wish to pursue a transmission project to meet individual state or mutual public policy goals, those states may utilize the State Agreement Approach to do so.

The hallmark of the State RTEP Committee will be its voluntary nature. As a PJM forum focused on state interest in regional transmission expansion, it will provide a vehicle for a state, or group of states, to participate more actively in the RTEP FYI Process than current RTEP protocol vehicles support today. But doing so does not commit them to any specific transmission project or otherwise imply an endorsement or support for any specific transmission projects. Only if the state or group of states pursues a project through the State Agreement Approach, would they need to demonstrate a commitment and indicate support for a specific transmission project. Any formal participation in RTEP transmission expansion will only be initiated by states themselves through the State Agreement Approach. The State RTEP Committee would be open to the agencies of the states deemed appropriate by the states, themselves.

**Communication Vehicles**

Analyses done as part of the FYI process form the basis of information that RTEP decision-making under the State Agreement Framework, Critical Mass Framework and Proactive Build Framework, as discussed further in Section III. This builds on recent RPPTF discussions recommending additional reporting to increase information exchange transparency. Additional details on the following topics may provide valuable information to market participants and states in assessing various transmission expansion drivers⁴:

- CETO development

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⁴ As part of load deliverability analysis, PJM first establishes a Capacity Emergency Transfer Objective ("CETO") for each load deliverability area ("LDA"). CETO is the amount of energy that the transmission system must be capable of delivering to the LDA being tested in order to avoid shedding load due solely to the risk of its inability to import needed capacity assistance during a capacity emergency. The Capacity Emergency Transfer Limit ("CETL") is determined from the actual Load Deliverability power flow analysis and expresses the maximum MW that an LDA can import under specified peak load test conditions.
- CETLs, NERC reliability criteria violations
- Identify “next limit(s) out” – i.e., next violation and CETL deliverability margin

PJM will develop expanded and enhanced reporting vehicles in order to publish more information and do so more frequently than today. New formats will move beyond today’s TEAC meeting material presentation formats. They will evolve, particularly during early phases of FYI process implementation, as stakeholder interactions with PJM yield new ideas to facilitate the exchange of information.
III. Implementing New Decision-making Approaches

An expanded decision-making framework will provide new approaches through which new transmission can be incorporated into PJM's RTEP.

Section III describes three new transmission expansion decision making approaches with an emphasis on how each integrates with the "FYI Process."

1. State Agreement Approach
2. Critical Mass Approach
3. Proactive Build Approach

These new approaches will provide for a broader perspective on transmission expansion need, beyond that currently defined in the planning process with respect to reliability and market efficiency. Taken together, all of these approaches will build on the foundation of information exchange established through the FYI process. It may be that the vast majority of RTEP projects continue to be justified based on reliability criteria. But even in those cases, the FYI process will inform reliability-based decisions by defining the range of assumptions and scenarios against which reliability criteria tests will be performed. Similarly, the assumptions and scenarios driving market efficiency decisions will flow out of the stakeholder interactions that comprise the FYI process.

Exhibit 6, below, shows the interaction of each approach with the FYI Process and how each would interact the others.

Exhibit 6: FYI Process and Decision Framework
The subsections which follow describe each decision-making approach in more detail.

1. **State Agreement Approach**

Decision making under the State Agreement Approach will be facilitated by effective two-way information flow and dialog between PJM and the states within the context of the FYI Process. This includes providing up-front input on assumptions and scenario analysis as well as coordinated analysis and review of FYI Process study and scenario results, ultimately facilitating high level consideration of multiple drivers and solution alternatives.

*Voluntary Participation and Safe Harbor*

The State RTEP Committee envisioned in this approach directly parallels the function of the TEAC and the Sub-regional RTEP Committees. The committees would be open to the agencies of the states deemed appropriate by the states, themselves.

As Section II indicates, the hallmark of the State Agreement Approach is its voluntary nature. As a PJM forum focused on state interest in regional transmission expansion, it will provide a vehicle for a state, or group of states, to participate more actively in the RTEP FYI Process than current RTEP protocol vehicles support today, but will not impose obligations on the states as a result of their participation.

Participation in State Agreement based projects will also provide for a “safe harbor” from commitment to cost sharing with respect to specific RTEP projects driven by public policy goals of other states.

Additionally, future RTEP expansion plans will protect any transmission capability already associated with state commitment portions of RTEP projects so as to ensure that such capability may be used to satisfy the intended goal of the state(s). For example, transmission capability implemented through the State Agreement Approach to support a group of wind-powered generation projects driven by a state public policy goal could not be subsequently considered as capability available to support, for example, a separate fossil fuel plant’s interconnection request need for network upgrades which that RTEP project might be otherwise available to provide.

*The “Off-ramp” Concept*

The overall expanded participation that the State Agreement decision-making approach offers will permit states to decide for themselves the degree to which they remain engaged with broader FYI Process study and communication process activities - including ongoing State RTEP Committee activities - that inform PJM’s broader expansion plan decision-making. Or, having considered the direction such decision-making activities may take, states may decide to pursue their own “off-ramp” transmission expansion opportunities. It should be made clear that the development of such “off-ramp” projects will continue to run in parallel with other PJM RTEP activities. By pursuing such a project, states will not separate or exclude themselves from the ongoing efforts of the planning process. Rather, their potential projects will be evaluated along with all drivers and other solution options to provide the states ultimate flexibility to pursue, adjust or abandon their projects as they see fit.
What does “off-ramp” consideration provide?

At its most fundamental, an off-ramp from the FYI Process would permit states - either individually or in collaboration with one another – the opportunity to choose to act by themselves to pursue specific transmission expansion plans to meet public policy objectives within the context of PJM’s RTEP protocol. Regardless, consideration of off-ramp opportunities will proceed between states and PJM in parallel with the ongoing FYI Process.

Myriad public policy factors – taken together or individually – could affect states decision-making on specific transmission expansion projects, including the following:

- Resource decisions regarding “buy (import), build (generation) and save (demand response and energy efficiency)”
- Enacted RPS standards
- Project costs
- State economic considerations in terms of jobs, tax revenue, etc.

However, state off-ramp approaches will not negate the need for state-based transmission solutions to be integrated into the rest of the PJM RTEP. PJM has a FERC-specified obligation to conduct studies that would assess the integration of such projects in the RTEP to ensure that all reliability criteria continue to be met.

Evaluating Off-ramp Projects

Pursuing an off-ramp transmission enhancement opportunity will necessarily proceed in collaboration with PJM. This collaboration will provide states the opportunity to participate in assessing, analyzing and studying initial project need. States may work with PJM to pursue more detailed consideration of specific conceptual projects to be evaluated by PJM, within practical limits. Importantly, a group of interested states supporting the initial evaluation of a project could indeed be different from the group of states that may support ultimate project development.

PJ M could include, if the interested states so desire, a project development phase in its RTEP protocol to facilitate collection of costs through PJM billing. The state / PJ M evaluation process could be structured to recognize the life cycle of a conceptual project: (1) The process could be staged; (2) the process would be flexible and provide increasingly detailed analysis in stages; and, (3) each stage would require increasingly detailed information about the conceptual projects being studied.

Project Development and Optimization with Existing RTEP

Consideration of state off-ramp projects will likely require some level of project design to facilitate RTEP integration analysis. PJ M would perform the analysis to assist in the identification of benefits in order to provide states information they will need to make decision regarding whether or not to pursue public policy projects. This would likely to include the following steps:

- More detailed engineering to be supplied to PJM
• Identification of associated network requirements
• Identification of and coordination with other drivers
• Identification of relative benefits

PJM’s overall role will be to work with states on transmission expansion plans that they voluntarily decide merit consideration in order to achieve respective public policy goals. Reliable integration of all power system elements - transmission, generation, etc. – consistent with established NERC reliability criteria will remain PJM’s primary job.

PJM integration studies will help states understand potential costs of upgrades needed to ensure reliability under their proposals. Interested states would determine cost sharing among themselves for project development costs (including engineering design work necessary for PJM to be able to perform integration analysis)

Here then is where the State Agreement Approach could also interact with Critical Mass decision making. Excess capability of a state off-ramp project could address need revealed by PJM studies assessing other expansion planning drivers. Adjustments or enhancement to a state off-ramp project could be considered if studies indicate that such would be more effective at meeting a wider range of needs. In such a case, the relative benefits associated with different drivers would serve as basis for the allocation of costs between state policy drivers and other RTEP drivers. Allocation of costs unrelated to state drivers would not be allocated to states, but would otherwise proceed according to PJM allocation rules then in effect.

State Commitment to an Off-ramp Project

PJM would not require state commitment to develop a project until a point in the decision process after PJM evaluates the project from an RTEP integration perspective. At that point, however, PJM will need some reasonable form of state commitment to an upgrade projects to provide assurance to PJM that those projects are likely to remain within the RTEP once approved by the PJM Board (absent other potential mitigating factors). Once included in the RTEP, subsequent analyses will reflect the impact of the project. Determinations as to future reliability requirements or the interconnection requirements of generation projects will necessarily produce different results with and without the state project included. While no absolute certainty can exist that any project will ultimately be placed in service, some level of commitment is required to ensure the ongoing integrity of the RTEP.

Post-Commitment

PJM must ensure, moving forward, that the transmission capability of a given state project, included in the PJM RTEP, for a given purpose (e.g. renewable energy deliverability) be protected for that intended purpose. At a minimum, future FYI Process PJM RTEP analysis will have to preserve such rights, similar to the manner in which generator Capacity Interconnection Rights are preserved today.

In that same vein, from a generation interconnection perspective, rules for access to transmission project capability would depend on how a state structures it. For example, if a project was driven by RPS requirements, states could hold a solicitation for that capability in the context of PJM’s generation interconnection queue process. The generation interconnection would still have to be evaluated by PJM, but would rely on capability reservations per state direction.
More broadly, regulatory provisions governing suspension or cancellation of state participation in a transmission project will have to be developed to address how such a situation would be resolved, given the interaction of the original drivers justifying the project. These provisions will need to be specified post-commitment both prior-to and after construction begins.

Once constructed, a transmission enhancement project by states would be operated by PJM as part of the region-wide transmission system.

**Additional Framework Design Elements for Further Consideration**

While the potential benefits to states under this approach are significant, a number of additional framework design elements must be considered before states and PJM implement formal RTEP protocol changes, for example:

- What form will state project commitment comprise in order for PJM to include state-proffered transmission expansions in the PJM RTEP?

- What cost sharing methodology should be adopted when a transmission project is based on multiple system expansion drivers, including State Agreement based drivers and non-state drivers? (See discussion of Critical Mass Approach.)
  - States themselves will decide how state driver related project-specific costs will be shared among them.
  - PJM cost-benefit analysis will inform the decision-making among a group of states how to share the costs of a specific transmission expansion upgrade

- Safe harbor from costs associated with transmission projects based on similar drivers in other states.

Nonetheless, PJM will continue to work with states to enhance their ability to participate in transmission expansion planning within PJM.

2. **Critical Mass Decision Making Approach**

The Critical Mass decision-making approach will focus on reaching commitment to a project justified on the basis of considering multiple drivers, as in the following cases:

- Commitment to a project justified to address one bright line driver (for example, baseline reliability) but with capability larger than required to address that driver alone, based on the expectation that sufficient additional drivers (for example, public policy) exist to justify the additional transmission capability.

- Commitment to a larger scale project which cannot be justified on the basis of any one driver individually. Yet, if several drivers are just below their individual system expansion triggers, perhaps, they may be sufficiently additive to justify collective consideration as a trigger to a particular transmission expansion project. Or,
Commitment to one larger-scale comprehensive project in place of several smaller, incremental upgrades which would otherwise be required to justify, for example, multiple, queued generation interconnection requests that have reached the ISA stage.

In essence, Critical Mass projects could be used to consolidate need based on some combination of baseline reliability, market efficiency, interconnection request and public policy drivers.

Thus, the Critical Mass approach would permit consideration of reliability drivers coupled with pending interconnection projects as well as the consideration of at-risk generation drivers coupled with pending interconnection projects. This would also permit further consideration of such justification with State Agreement project drivers or market efficiency project drivers. The Critical Mass approach would also be sufficiently flexible to provide a mechanism by which to integrate transmission expansion based on interregional drivers.

Interaction with the FYI Process

The FYI process would provide stakeholders – market participants and states, alike – greater up-front opportunity to provide input on modeling assumptions and analytical scenarios, and post-analysis opportunity to review and discuss study results. The analysis component of the FYI Process will, thus, also comprise additional, extensive scenario studies per stakeholder input.

Analyses performed as part of the FYI process will form the basis for consideration of potential transmission expansion alternatives under the Critical Mass decision-making approach. In such instances, PJM's FYI results will provide information on the relative benefits of alternative upgrade solutions that may address multiple drivers, benefits which may also provide important input to cost allocation.

Overall, the FYI process will afford PJM the opportunity to publish and communicate a wide range of results the goal of which is to “send signals” to stakeholders and inform Critical Mass discussions. Doing so will allow market participants and states to make their own respective informed decisions on what transmission opportunities to pursue.

Interaction with State Agreement Decision-making Approach

The Critical Mass approach will be based on FYI Process identification of the most effective solution and benefits associated with multiple drivers, including drivers that may be the basis of projects under consideration by the states through the State Agreement approach. The Critical Mass Decision-making approach provides a mechanism for PJM and stakeholders to consider triggering expansion plans to the extent that multiple drivers suggest the merit of doing so, plans which may or may not be justified based on the strength of the need that one or more individual drivers may demonstrate. If states so choose – individually or in collaboration with one another – they may elect to pursue projects that best meet their needs through the State Agreement approach but also serve other needs based on decision making under the Critical Mass Approach.

States would need only to determine cost allocation among themselves, to the extent such would be required, for the portion of the capability of a Critical Mass project that is specifically dedicated to state needs as a State Agreement project. Costs related to other drivers will be allocated according to the relative benefit provided by those drivers, per analyses conducted by PJM.
Generation Interconnection Request Perspective

The Critical Mass approach could identify transmission projects even if 100% of the capability is associated with interconnection requests that have reached the System Impact Study Phase. Consideration will be given to whether or not incremental upgrades are less expensive than an allocated share of large-scale upgrade cost. Yet, even though incremental upgrades may be faster to build, incremental upgrades are often rendered obsolete as subsequent Impact Studies are completed and larger-scale projects are justified.

Additional Framework Design Elements for Further Consideration

As with the State Agreement approach, while the potential benefits to stakeholders under the Critical Mass approach are significant, a number of additional framework design elements must be considered before states and PJM implement formal RTEP protocol changes, for example:

- What cost sharing methodology should be adopted when multiple system expansion drivers are involved? Is the allocation among drivers in any way different if some drivers are the result of a State Agreement decision-making process?
  - PJM cost-benefit analysis will inform the decision-making among drivers and between state-related drivers and non-state drivers
  - Cost allocation for capability associated with non-state drivers will be based on the blend of needs driving a project
- How should capability be accounted-for when comparing reliability, market efficiency, and other drivers?
- How many other potential drivers must exist related to excess capability above reliability drivers to provide reasonable certainty that a Critical Mass project will be needed?
- How will interconnection analysis be integrated with RTEP analysis for a Critical Mass project?
- How will cost responsibility be established for generators related to a Critical Mass project?

Nonetheless, PJM will continue to work with stakeholders to consider resolve these issues and implement the Critical Mass approach.

3. Proactive Decision Making Approach

Integration of a Proactive decision-making approach with the FYI Process will provide a third avenue through which new transmission can be incorporated into PJM’s RTEP. Doing so will offer yet another opportunity to justify transmission expansion need beyond that which already exists in terms of bright line reliability and market efficiency triggers, or which may emerge from State Agreement and Critical Mass considerations.
**Proactive Approach Description**

Under the Proactive decision-making approach, PJM may identify strong justification for transmission expansion needed to solve overwhelming reliability criteria violations identified in FYI Process public policy scenario analyses. Such violations would comprise those that go beyond those that FYI Process baseline reliability bright line analysis would identify. For example, an FYI at-risk generation scenario analysis could potentially reveal reliability criteria violations of such severity and geographic reach as to justify consideration of transmission enhancements not otherwise identified as part of baseline reliability analysis.

Given the nature of PJM’s proposed decision-making under this approach, justifying such transmission expansion proactively will necessarily require the implementation of triggers set sufficiently high enough to minimize the potential for whip-sawing of potentially volatile factors driving expansion need. Indeed, triggers may have to be tailored to each public policy factor individually. Then, depending on nature of the trigger, cost allocation could follow current rules or be project specific.

**Additional Framework Design Elements for Further Consideration**

As with the Critical Mass and State Agreement approaches, the potential future reliability benefits to stakeholders of the Proactive approach are significant. Yet, several additional framework design elements must be considered before states and PJM implement formal RTEP protocol changes, for example:

- How much latitude and authority would PJM have to determine how much transmission is needed, where and timing?
- More philosophically, what should be the scope of PJM’s role to make such decisions and impose cost burdens on members?

PJM will continue to work with stakeholders to consider resolve these issues and implement the Critical Mass approach.
IV. Next Steps

PJM and the Regional Planning Process Working Group (RPPTF) have made significant strides over the past year exploring ways to improve the RTEP Protocol in order to address a number of emerging factors, not least of which is the emergence of state-based public policy initiatives. This white paper has attempted to capture PJM’s and the RPPTF’s current thinking and proposed process and decision-making approaches to expand the flexibility of RTEP Protocol to address a changing planning landscape.

Clearly, though, additional thought and discussion are required to determine specific PJM Operating Agreement Schedule 6 and PJM Manual 14-B modifications required to implement the concepts which this white paper describes, even more so as PJM and stakeholders continue to address FERC’s Order 1000 compliance.

A key part of that thought and discussion, prior to any formal Operating Agreement FERC filings and Manual 14-B modifications, will be for PJM and stakeholders to prioritize and sequence required agreement and manual modifications given that some RTEP protocol concept changes discussed in this white paper are indeed more fully defined at this point than others. Thus, more than one set of Operating Agreement filing and Manual 14-B modifications may actually be needed over the course of the next year or so.
NorthEast Chapter
Energy Bar Association
“Transmission and NYS Efforts”

Garry Brown
NYS Public Service Commission
June 6, 2012

STATEWIDE PLANNING
NYISO Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP)

- Part of NYISO’s Comprehensive System Planning Process
- Provide assessment of bulk electric system reliability over a 10-year horizon to determine how reliability needs in the state will be met.
- Studies conclude that through 2020 no reliability needs identified, assuming all existing generation facilities, including Indian Point.

STATEWIDE PLANNING
Congestion Assessment and Resource Integration Study (CARIS)

- NYISO conducted biennially in conjunction with RNA & CRP
- Identifies opportunities for economic upgrades & possible projects that could resolve congestion during next 10-year period.
- CARIS Phase I report Mar. 20, 2012—Generic project upgrades along the most congested NYS corridor identified were found to be only marginally economic.
- Base cases currently being readied for any specific project proposals that may be submitted for a CARIS Phase II study by project developers.
Establishment of Installed Reserve Margin (IRM) Requirement:

- The New York Control Area IRM Study conducted annually by the NYSRC to establish IRM requirements for following capability year.
- IRM determines how much installed capacity must exist to ensure that loss of load expectation is no more than once in 10 years.
- Latest IRM released Dec. 2, 2011. Installed Reserve margin capability year from May 2012 through April 2013 was set at 16.1% (up from 15.5%).
- An IRM of 16.1% was approved by NYS Public Service Commission in Feb. 2012.

State Transmission and Reliability Study (STARS)

- TOs study evaluate long-term (up to 30 years) need to build, upgrade, refurbish, retire transmission facilities to maintain reliability considering load growth, asset condition and public policy.
- Phase I completed in Jan. 2010—identify need for add'l. transfer capability to meet statewide LOLE w/ existing transmission system.
- Phase II completed in April 2012—over 70 potential transmission projects identified (many target toward wind deliverability).
- Phase II key findings—NYS electric infrastructure is continually aging & approximately 40% of existing transmission likely need replacement over next 30 years.

NYISO Analysis of New EPA/NYSDEC Regs

- Impacted plants already identified by proposed NYSDEC regs & approx. investment required by each also identified.
- Next step look at economic feasibility of meeting NYSDEC reqm'ts.
- Changes to many federal EPA regs cause flux in study results.
- Current belief new EPA rules, as proposed, result in significant portion of NYS fossil fuel powered fleet to be adversely impacted.
- NYISO report expected later this year.
LOCAL PLANNING

Utility Electric Long Range Plans

• All NYS utilities expected to develop & implement long-range (15-20 year) plans addressing aging infrastructure, projected load growth, and public policy initiatives as well as potential rate impacts.

• All utilities have submitted proposed electric long range plans which will be incorporated into the NYISO’s 2012 RNA base cases.

• Updates will be made as conditions change.

LOCAL PLANNING

NYSPSC Demand Response (DR) Proceeding

• Feb. 2009, NYSPSC instituted a proceeding to assess the potential for cost-effective demand response in Con Edison’s (NYC) Zone J.

• Potential benefits of DR include: deferring need for new generating capacity and/or need for new transmission & distribution infrastructure, reducing emissions by reducing the need to operate older peaking generation facilities; improving local air quality, particularly in Environmental Justice areas; and reducing energy and capacity costs for consumers.

• Based on summer 2010 summer results and stakeholder input, in Jan. 2011, the NYSPSC approved a number of changes in Con Edison DR programs to facilitate & enhance customer participation for 2011.

LOCAL PLANNING

NYC Transmission Study

• Master Transmission Plan or optimal expansion of NYC’s transmission infrastructure w/ next five years.

• Goals of Master Plan: reduce electricity production costs & cost of service for NYC ratepayers; improve NYC diversity of fuel supply; reduce NYC electricity “carbon footprint,” and improve reliability of bulk power supply to NYC.

• Final report, issued Mar. 2009, indicates there is “no low-hanging fruit” when it comes to an economic project in NYC.
REGIONAL/NATIONAL PLANNING
Eastern Interconnection Planning Collaborative (EIPC)

• Perform eastern interconnection-wide planning analysis: 1) incorporates all existing regional plans to ensure compatibility and 2) perform scenario analysis to evaluate implementation impacts and strategies.

• Phase I completed Dec 2011; three scenarios selected for continued analysis in Phase II—1) continued biz as usual; 2) national policy on renewable implemented at a regional level; 3) national policies on carbon reduction, renewable, energy efficiency/demand resources.

• Phase II is planned for completion by end of 2012.

REGIONAL/NATIONAL PLANNING
Transmission Adequacy Studies-2011 NE Coordinated System Plan (NCSP)

• ISO-NE, NYISO, PJM follow a planning protocol to enhance coordination of planning activities and address planning seams issues among interregional balancing authority areas.

• 2011 NCSP in drafting stage with significant consideration of interregional cost allocation and planning to meet new reqm'ts of FERC Order 1000; impacts of environmental regs also considered.


REGIONAL/NATIONAL PLANNING
DOE Congestion Study

• Federal Power Act, as modified by EPA of 2005 requires DOE to perform a congestion study every three years to identify constrained transmission paths throughout U.S.

• 2006 DOE Congestion Study designation most of NYS as a NEITC.

• 2009 DOE Congestion Study calls NY’s congestion problematic; study results based on many errors in modeling the NY system.

• 2012 DOE congestion Study is underway.
REGIONAL/NATIONAL PLANNING
Eastern Wind Integration & Transmission Study (EWITS)

• EWITS led by DOE/NREL focusing on costs & operating impacts of wind penetration scenarios (20% penetration by 2030 in U.S.—with up to 30%) on the power system in Eastern Interconnect of U.S.

Findings:
• 20-30% penetration is technically feasible; new transmission would need to be built (and address transmission before generation)
• w/o new transmission, curtailments required for all 20% penetration scenarios
• Costs of integration of large amounts of wind are "manageable;" in all 20% penetration scenarios, wind displaces coal.

REGIONAL/NATIONAL PLANNING
Joint Coordinated System Plan (JCSP)

• JCSP study a joint initiative by MISO, PJM, SPP, TVA, MAPP, NYISO and NEISO in collaboration with DOE to determine the extra-high voltage (345 kV and above) system reinforcements required across entire eastern interconnection to:

  • Site new wind resources to equal 20% of energy needs (proposed DOE req'mt) by 2024; and with the 20% wind resources, to eliminated 80% of congestion on EHV system. This effort lead by Midwest ISO in cooperation with the NYISO, PJM, ISO-NE, SPP, TVA and MAPP. Report completed in 2008.

  • NYISO (and PJM & NEISO) noted study did not consider possibility of Northeast developing more localized infrastructure upgrades to integrate substantial indigenous renewable resources in region.

REGIONAL/NATIONAL PLANNING
FERC Order 1000

• Requires transmission providers (NYISO & TOs) to include procedures in OATT by which "transmission needs driven by Public Policy Requirements will be identified in the local & regional transmission planning processes and how potential solutions to the identified transmission needs will be evaluated in processes."

• Transmission providers compliance filing with FERC due Oct. 2012. NYSPSC staff, NYISO, TOs have had discussions to implement Order No. 1000; a 'straw proposal' is scheduled to be released shortly.

• Straw proposal provides a path for the identification of state and federal policies that can lead to a need for new transmission, identified a path for considering project to meet the need, and –if required- identified how project costs could be recovered.
Energy Bar Association
Northeast Chapter
Order No. 1000-A
Anna Cochrane, Deputy Director
Office of Energy Market Regulation
Federal Energy Regulatory Commission
June 6, 2012

The author’s views do not necessarily represent the views of the Federal Energy Regulatory Commission.

Timeline

• Order No. 888 in 1996
  - Requires open access to transmission facilities to address undue discrimination and to bring more efficient, lower cost power to the Nation’s electricity consumers

• Order No. 890 in 2007
  - Requires coordinated, open and transparent regional transmission planning processes to address undue discrimination

• Order No. 1000 in 2011
  - Requires transmission planning at the regional level to consider and evaluate possible transmission alternatives and produce a regional transmission plan
  - Requires the cost of transmission solutions chosen to meet regional transmission needs to be allocated fairly to beneficiaries

• Order No. 1000-A in 2012
  - Denies rehearing, but provides a number of clarifications.

Citations


Order No. 1000

- Planning Requirements
- Cost Allocation Requirements
- Nonincumbent Developer Requirements
- Compliance

Important Terms

- Rule distinguishes between a transmission facility "in a regional transmission plan" and "selected in a regional transmission plan for purposes of cost allocation"
- Rule’s requirements apply to “new transmission facilities,” which are those subject to evaluation or reevaluation within local or regional transmission planning processes after the effective date of compliance filings

PLANNING REQUIREMENTS
Planning Requirements

1. Public utility transmission providers are required to participate in a regional transmission planning process that satisfies Order No. 890 principles and produces a regional transmission plan.

2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations.

3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if more efficient or cost-effective solutions are available.

Planning Requirements - Order No. 1000-A

- Clarifies that each planning region must have a clear enrollment process that defines how entities, including non-public utility transmission providers, make the choice to become part of the region.

- A non-public utility transmission provider is not required to join a transmission planning region, but if it elects to enroll, it will be subject to the region’s regional and interregional cost allocation methods.
  - If it elects not to enroll, it can participate in the process as a stakeholder.
  - The regional transmission planning process is not required to plan for its needs.

Regional Planning

- Each transmission planning region must produce a regional transmission plan reflecting solutions that meet the region’s needs more efficiently or cost-effectively.

- Stakeholders must have an opportunity to participate in identifying and evaluating potential solutions to regional needs.
Planning for Public Policy Requirements

• Each public utility transmission provider must establish procedures to:
  – Identify transmission needs driven by public policy requirements
  – Evaluate potential solutions to those needs

• Public policy requirements are defined as enacted statutes and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level

• No mandate to include any specific requirement

Planning for Public Policy Requirements - Order No. 1000-A

• Clarifies that Order No. 1000 requires the consideration of transmission needs driven by Public Policy Requirements, not the consideration of Public Policy Requirements themselves.

• States these reforms are necessary because the record shows there are, and will continue to be, federal and state laws and regulations that will have a direct impact on transmission needs, just as reliability and economic concerns have a direct impact on transmission needs.

• Reiterated (citing NAACP v. FERC) that the consideration of transmission needs driven by Public Policy Requirements “cannot be construed as pursuing broad general welfare goals that extend beyond matters subject to our authority under the FPA.”

Interregional Coordination

• Each pair of neighboring transmission planning regions must:
  – Share information regarding the respective needs of each region and potential solutions to those needs
  – Identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs

• Interregional transmission facilities are those that are located in two or more neighboring transmission planning regions

• No requirement to produce an interregional transmission plan or engage in interconnectionwide planning
Cost Allocation Requirements

1. Regional transmission planning process must have a regional cost allocation method for a new transmission facility selected in the regional transmission plan for purposes of cost allocation
   - Cost allocation method must satisfy six regional cost allocation principles
2. Neighboring transmission planning regions must have a common interregional cost allocation method for a new interregional transmission facility that the regions select
   - Cost allocation method must satisfy six similar interregional cost allocation principles
3. Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method

Cost Allocation Principles

- Costs allocated “roughly commensurate” with estimated benefits
- Those who do not benefit from transmission do not have to pay for it
- Benefit-to-cost thresholds must not exclude projects with significant net benefits
- No allocation of costs outside a region unless other region agrees
- Cost allocation methods and identification of beneficiaries must be transparent
- Different allocation methods could apply to different types of transmission facilities
The rule does not require a one-size fits all method for allocating costs of transmission facilities.
- Each region is to develop its own proposed cost allocation method(s).

If region can’t decide on a cost allocation method, then FERC would decide based on the record.

No interconnectionwide cost allocation.

The Commission reaffirmed that a preexisting contract is not necessary to establish a cost allocation.
- Order cites Connecticut Light & Power Co. v. F.P.C., 324 U.S. 515, 529 (1945), where the Supreme Court has stated that the Commission’s jurisdiction is “to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.”

Contracts do not reflect the actual flow of electric energy on the transmission grid. Nor do contracts define or limit the benefits that an entity receives from its use of the transmission grid.

Commission states: “This explains why the cost allocation provisions of Order No. 1000, which seek to allocate costs to beneficiaries in a region roughly commensurate with benefits they receive, are consistent with the statement in Illinois Commerce Commission that “[a]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.” (citing Illinois Commerce Commission, 576 F.3d 470)

Given the nature of cost causation itself, some entities that actually cause costs would not be required to pay them if they could utilize the absence of a contractual relationship to shield themselves from an allocation of costs.
Cost Allocation
Order No. 1000-A

- Neither Order No. 1000 nor Order No. 1000-A addresses cost recovery.
  - Order No. 1000-A clarifies that compliance filings can include provisions addressing cost recovery and cost containment if public utility transmission providers, in consultation with stakeholders, choose to do so.

NONINCUMBENT DEVELOPER REQUIREMENTS

Nonincumbent Developers

- Rule promotes competition in regional transmission planning processes to support efficient and cost effective transmission development
- Rule requires the development of a not unduly discriminatory regional process for transmission project submission, evaluation, and selection
Nonincumbent Developers

Rule removes any federal right of first refusal from Commission-approved tariffs and agreements with respect to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:

- This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
- This does not apply to upgrades to transmission facilities, such as tower change outs or reconductoring.
- This allows, but does not require, the use of competitive bidding to solicit transmission projects or project developers.
- Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.

Nonincumbent Developers Order No. 1000-A

• Reiterates that claims that a federal right of first refusal in a Commission-approved agreement is protected by a Mobile-Sierra are properly made part of an Order No. 1000 compliance filing.
• Before addressing proposed tariff revisions to comply with the rule, FERC will decide whether the agreement is protected by a Mobile-Sierra provision, and if so, whether the applicable standard of review to require removal of the right of first refusal has been met.

Nonincumbent Developers Order No. 1000-A

• Affirms requirement for each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions.
• Clarifies that it will not subject a Registered Entity to a penalty for a violation of a NERC reliability standard caused by a nonincumbent transmission developer’s decision to abandon any type of transmission facility selected in the regional transmission plan for purposes of cost allocation if, on a timely basis, that Registered Entity identifies the violation and complies with all of its obligations under the NERC reliability standards to address it.
Nonincumbent Developers
Order No. 1000-A

- Clarifies that the definition of a nonincumbent transmission developer can include independent transmission companies and non-public utilities.
- However, the Commission also explains that all nonincumbent transmission developers that have load in a region, or have an affiliate that has load in a region, must enroll in that region to be permitted to propose a transmission project for selection in a regional transmission plan for purposes of cost allocation in that region.

Nonincumbent Developers
Order No. 1000-A

- Clarify that it would be an impermissible barrier to entry to require, as part of the qualification criteria, that a transmission developer demonstrate that it either has, or can obtain, state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility.
- Reiterates the qualification criteria must be fair and not unreasonably stringent when applied to an incumbent transmission provider and a nonincumbent transmission developer.

Reciprocity – Order No. 1000-A

- Clarifies that the reciprocity requirement under Order Nos. 888 and 890 remains unchanged.
- A non-public utility transmission provider may continue to satisfy the reciprocity condition in one of three ways:
  1) it may provide service under a tariff that has been approved by the Commission under the voluntary “safe harbor” provision of the pro forma OATT.
  2) it may provide service to a public utility transmission provider under a bilateral agreement that satisfies its reciprocity obligation.
  3) it may seek a waiver of the reciprocity condition from the public utility transmission provider.
Compliance

- Each transmission provider is required to make a compliance filing within twelve months of the effective date of the Final Rule [Oct. 11, 2012]

- The compliance filings for interregional transmission coordination and interregional cost allocation must be filed within eighteen months of the effective date [April 11, 2013]

Outreach

FERC held 3 webinars in September to aid compliance:
- RTO regions
- Eastern (non-RTO)
- Western (non-RTO)

Commission staff is monitoring the regional compliance efforts

For updates, please follow us:
- Twitter twitter.com/ferc
- Facebook facebook.com/ferc.gov
- RSS ferc.gov/xml/whats-new.xml
Court Cases

Associated Gas Distrib. v. FERC, 824 F.2d 981 (D.C. Cir. 1985).

Atlantic City Elec. Co. v. FERC, 295 F.3d 1 (D.C. Cir. 2002).


Central Iowa Power Coop. v. FERC, 606 F.2d 1156 (D.C. Cir. 1979).


Illinois Commerce Commission v. FERC, 576 F.3d 470 (7th Cir. 2009).


National Fuel Gas Supply Corp. v. FERC, 468 F.3d 831 (D.C. Cir. 2006).

FERC Orders


Market Mitigation, Capacity Markets and Market Design: Are They Working as Intended?
Market Power Mitigation, Capacity Markets and Market Design: Are They Working As Intended?

Energy Bar Association

Joseph Bowring

June 6, 2012
Table 1-7 Total price per MWh by category and total revenues by category: January through March 2011 and 2012 (See 2011 SOM, Table 1-7)

<table>
<thead>
<tr>
<th>Category</th>
<th>Jan-Mar 2011 $/MWh</th>
<th>Jan-Mar 2012 $/MWh</th>
<th>Percent Change Totals</th>
<th>Jan-Mar 2011 Percent of Total</th>
<th>Jan-Mar 2012 Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>$46.35</td>
<td>$31.21</td>
<td>(32.7%)</td>
<td>70.7%</td>
<td>68.6%</td>
</tr>
<tr>
<td>Capacity</td>
<td>$12.60</td>
<td>$7.51</td>
<td>(40.4%)</td>
<td>19.2%</td>
<td>16.5%</td>
</tr>
<tr>
<td>Transmission Service Charges</td>
<td>$4.32</td>
<td>$4.80</td>
<td>11.1%</td>
<td>6.6%</td>
<td>10.6%</td>
</tr>
<tr>
<td>Operating Reserves (Uplift)</td>
<td>$0.72</td>
<td>$0.49</td>
<td>(31.6%)</td>
<td>1.1%</td>
<td>1.1%</td>
</tr>
<tr>
<td>Reactive</td>
<td>$0.39</td>
<td>$0.48</td>
<td>23.8%</td>
<td>0.6%</td>
<td>1.1%</td>
</tr>
<tr>
<td>PJM Administrative Fees</td>
<td>$0.33</td>
<td>$0.36</td>
<td>10.4%</td>
<td>0.5%</td>
<td>0.8%</td>
</tr>
<tr>
<td>Transmission Enhancement Cost Recovery</td>
<td>$0.30</td>
<td>$0.28</td>
<td>(7.3%)</td>
<td>0.5%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Regulation</td>
<td>$0.27</td>
<td>$0.17</td>
<td>(36.6%)</td>
<td>0.4%</td>
<td>0.4%</td>
</tr>
<tr>
<td>Transmission Owner (Schedule 1A)</td>
<td>$0.09</td>
<td>$0.08</td>
<td>(13.6%)</td>
<td>0.1%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Synchronized Reserves</td>
<td>$0.12</td>
<td>$0.03</td>
<td>(75.6%)</td>
<td>0.2%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Black Start</td>
<td>$0.02</td>
<td>$0.02</td>
<td>28.8%</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>NERC/RFC</td>
<td>$0.02</td>
<td>$0.02</td>
<td>8.9%</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>RTO Startup and Expansion</td>
<td>$0.01</td>
<td>$0.01</td>
<td>(10.9%)</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Load Response</td>
<td>$0.01</td>
<td>$0.01</td>
<td>18.5%</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Transmission Facility Charges</td>
<td>$0.00</td>
<td>$0.00</td>
<td>(3.2%)</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Day Ahead Scheduling Reserve (DASR)</td>
<td>$0.00</td>
<td>$0.00</td>
<td>(97.6%)</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Total</td>
<td>$65.56</td>
<td>$45.48</td>
<td>(30.6%)</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Table 1-2 The Capacity Market results were competitive

<table>
<thead>
<tr>
<th>Market Element</th>
<th>Evaluation</th>
<th>Market Design</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Structure: Aggregate Market</td>
<td>Not Competitive</td>
<td></td>
</tr>
<tr>
<td>Market Structure: Local Market</td>
<td>Not Competitive</td>
<td></td>
</tr>
<tr>
<td>Participant Behavior: Local Market</td>
<td>Competitive</td>
<td></td>
</tr>
<tr>
<td>Market Performance</td>
<td>Competitive</td>
<td>Mixed</td>
</tr>
</tbody>
</table>
Table 4-4 Preliminary market structure screen results: 2011/2012 through 2015/2016 RPM Auctions (See the 2011 SOM, Table 4-7)

<table>
<thead>
<tr>
<th>RPM Markets</th>
<th>Highest Market Share</th>
<th>HHI</th>
<th>Pivotal Suppliers</th>
<th>Pass/Fail</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011/2012</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RTO</td>
<td>18.0%</td>
<td>855</td>
<td>1</td>
<td>Fail</td>
</tr>
</tbody>
</table>

| 2012/2013   |                       |     |                  |          |
| RTO         | 17.4%                 | 853 | 1                | Fail     |
| MAAC        | 17.6%                 | 1011| 1                | Fail     |
| EMAAC       | 32.6%                 | 2057| 1                | Fail     |
| SWMAAC      | 50.7%                 | 4338| 1                | Fail     |
| PSEG        | 84.3%                 | 7188| 1                | Fail     |
| PSEG North  | 90.9%                 | 8287| 1                | Fail     |
| DPL South   | 55.0%                 | 3828| 1                | Fail     |

| 2013/2014   |                       |     |                  |          |
| RTO         | 14.4%                 | 812 | 1                | Fail     |
| MAAC        | 18.1%                 | 1101| 1                | Fail     |
| EMAAC       | 33.0%                 | 1992| 1                | Fail     |
| SWMAAC      | 50.9%                 | 4790| 1                | Fail     |
| PSEG        | 89.7%                 | 8069| 1                | Fail     |
| PSEG North  | 89.5%                 | 8056| 1                | Fail     |
| DPL South   | 55.8%                 | 3887| 1                | Fail     |
| JCPL        | 28.5%                 | 1731| 1                | Fail     |
| Pepco       | 94.5%                 | 8947| 1                | Fail     |

| 2014/2015   |                       |     |                  |          |
| RTO         | 15.0%                 | 800 | 1                | Fail     |
| MAAC        | 17.6%                 | 1038| 1                | Fail     |
| EMAAC       | 33.1%                 | 1966| 1                | Fail     |
| SWMAAC      | 49.4%                 | 4733| 1                | Fail     |
| PSEG        | 89.4%                 | 8027| 1                | Fail     |
| PSEG North  | 88.2%                 | 7825| 1                | Fail     |
| DPL South   | 56.5%                 | 3796| 1                | Fail     |
| Pepco       | 94.5%                 | 8955| 1                | Fail     |

| 2015/2016   |                       |     |                  |          |
| RTO         | 14.3%                 | 763 | 1                | Fail     |
| MAAC        | 17.5%                 | 1114| 1                | Fail     |
| EMAAC       | 32.6%                 | 1904| 1                | Fail     |
| SWMAAC      | 51.9%                 | 4745| 1                | Fail     |
| DPL South   | 49.2%                 | 3257| 1                | Fail     |
| PSEG        | 89.4%                 | 8020| 1                | Fail     |
| PSEG North  | 88.0%                 | 7794| 1                | Fail     |
| Pepco       | 94.1%                 | 8876| 1                | Fail     |
| ATSI        | 75.5%                 | 5981| 1                | Fail     |
Table 4-5 RSI results: 2011/2012 through 2014/2015 RPM Auctions (See the 2011 SOM, Table 4-8)

<table>
<thead>
<tr>
<th>RPM Markets</th>
<th>RSI1</th>
<th>RSI3</th>
<th>Total Participants</th>
<th>Failed RSI Participants</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011/2012 BRA RTO</td>
<td>0.85</td>
<td>0.63</td>
<td>76</td>
<td>76</td>
</tr>
<tr>
<td>2011/2012 First Incremental Auction RTO</td>
<td>0.86</td>
<td>0.62</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>2011/2012 ATSI FRR Integration Auction RTO</td>
<td>0.18</td>
<td>0.07</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>2011/2012 Third Incremental Auction RTO</td>
<td>0.54</td>
<td>0.41</td>
<td>52</td>
<td>52</td>
</tr>
<tr>
<td>2012/2013 BRA RTO</td>
<td>0.84</td>
<td>0.63</td>
<td>98</td>
<td>98</td>
</tr>
<tr>
<td>MAAC/SWMAAC</td>
<td>0.77</td>
<td>0.54</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>EMAAC/PSEG</td>
<td>0.00</td>
<td>7.03</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td>PSEG North</td>
<td>0.00</td>
<td>0.00</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>DPL South</td>
<td>0.00</td>
<td>0.00</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>2012/2013 ATSI FRR Integration Auction RTO</td>
<td>0.34</td>
<td>0.10</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>2012/2013 First Incremental Auction RTO/MAAC/SWMAAC/PSEG/EMAAC/PSEG/PSEG North/DPL South</td>
<td>0.40</td>
<td>0.60</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>EMAAC</td>
<td>0.40</td>
<td>0.00</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>2012/2013 Second Incremental Auction RTO/MAAC/SWMAAC/PSEG/EMAAC/PSEG/PSEG North/DPL South</td>
<td>0.62</td>
<td>0.64</td>
<td>33</td>
<td>33</td>
</tr>
<tr>
<td>EMAAC</td>
<td>0.00</td>
<td>0.00</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>2012/2013 Third Incremental Auction RTO/MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South</td>
<td>0.59</td>
<td>0.28</td>
<td>53</td>
<td>53</td>
</tr>
<tr>
<td>2013/2014 BRA RTO</td>
<td>0.80</td>
<td>0.59</td>
<td>87</td>
<td>87</td>
</tr>
<tr>
<td>MAAC/SWMAAC</td>
<td>0.42</td>
<td>0.23</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>EMAAC/PSEG/PSEG/EMAAC/PSEG North/DPL South</td>
<td>0.25</td>
<td>0.00</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Pepco</td>
<td>0.00</td>
<td>0.00</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>2013/2014 First Incremental Auction RTO/MAAC/SWMAAC/PSEG/EMAAC/PSEG/PSEG North/DPL South</td>
<td>0.24</td>
<td>0.28</td>
<td>33</td>
<td>33</td>
</tr>
<tr>
<td>EMAAC/PSEG/PSEG/EMAAC/PSEG North/DPL South</td>
<td>0.34</td>
<td>0.00</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>SWMAAC/Pepco</td>
<td>0.00</td>
<td>0.00</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2014/2015 BRA RTO</td>
<td>0.76</td>
<td>0.58</td>
<td>93</td>
<td>93</td>
</tr>
<tr>
<td>MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco</td>
<td>1.40</td>
<td>1.03</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>PSEG North</td>
<td>0.00</td>
<td>0.00</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>
Table 4-11 RPM revenue by type: 2007/2008 through 2014/2015
(See the 2011 SOM, Table 4-22)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Resources</td>
<td>$5,537,085</td>
<td>$35,349,116</td>
<td>$65,762,003</td>
<td>$60,235,796</td>
<td>$55,795,785</td>
<td>$264,387,898</td>
<td>$551,453,434</td>
<td>$666,313,051</td>
<td>$1,704,834,167</td>
</tr>
<tr>
<td>Energy Efficiency Resources</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$139,812</td>
<td>$11,408,552</td>
<td>$20,680,368</td>
<td>$38,571,074</td>
<td>$70,799,806</td>
</tr>
<tr>
<td>Imports</td>
<td>$22,225,980</td>
<td>$60,918,903</td>
<td>$56,517,793</td>
<td>$106,046,871</td>
<td>$185,421,273</td>
<td>$13,260,822</td>
<td>$31,191,272</td>
<td>$178,063,746</td>
<td>$653,646,660</td>
</tr>
<tr>
<td>Coal existing</td>
<td>$1,022,372,301</td>
<td>$1,844,120,476</td>
<td>$2,417,576,805</td>
<td>$2,662,434,386</td>
<td>$1,595,707,479</td>
<td>$1,016,194,603</td>
<td>$1,736,326,997</td>
<td>$1,827,519,210</td>
<td>$14,122,252,257</td>
</tr>
<tr>
<td>Coal new/reactivated</td>
<td>$0</td>
<td>$1,854,781</td>
<td>$3,168,069</td>
<td>$28,330,047</td>
<td>$7,414,940</td>
<td>$12,493,918</td>
<td>$32,877,767</td>
<td>$626,984,645</td>
<td>$110,179,060</td>
</tr>
<tr>
<td>Gas existing</td>
<td>$1,514,681,896</td>
<td>$1,951,345,311</td>
<td>$2,329,209,917</td>
<td>$2,632,336,161</td>
<td>$1,607,317,731</td>
<td>$1,117,382,927</td>
<td>$1,894,356,736</td>
<td>$2,003,810,846</td>
<td>$15,050,441,462</td>
</tr>
<tr>
<td>Gas new/reactivated</td>
<td>$3,472,667</td>
<td>$9,751,112</td>
<td>$30,168,831</td>
<td>$58,065,964</td>
<td>$98,448,693</td>
<td>$76,633,409</td>
<td>$166,414,514</td>
<td>$184,029,455</td>
<td>$626,984,645</td>
</tr>
<tr>
<td>Hydroelectric existing</td>
<td>$209,490,444</td>
<td>$287,850,403</td>
<td>$364,742,517</td>
<td>$442,429,815</td>
<td>$278,529,660</td>
<td>$179,117,975</td>
<td>$308,742,213</td>
<td>$328,877,767</td>
<td>$2,399,780,793</td>
</tr>
<tr>
<td>Hydroelectric new/reactivated</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$11,397</td>
<td>$17,520</td>
<td>$6,591,114</td>
<td>$6,620,031</td>
<td>$10,283,710,191</td>
</tr>
<tr>
<td>Nuclear existing</td>
<td>$996,085,233</td>
<td>$1,322,601,837</td>
<td>$1,517,723,628</td>
<td>$1,799,258,125</td>
<td>$1,079,386,338</td>
<td>$762,719,551</td>
<td>$1,346,024,263</td>
<td>$1,459,911,217</td>
<td>$10,283,710,191</td>
</tr>
<tr>
<td>Nuclear new/reactivated</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Oil existing</td>
<td>$448,034,948</td>
<td>$532,432,515</td>
<td>$663,370,167</td>
<td>$623,141,070</td>
<td>$368,084,004</td>
<td>$385,988,279</td>
<td>$620,740,652</td>
<td>$433,317,895</td>
<td>$4,075,109,531</td>
</tr>
<tr>
<td>Oil new/reactivated</td>
<td>$0</td>
<td>$4,837,523</td>
<td>$5,676,582</td>
<td>$4,339,539</td>
<td>$967,887</td>
<td>$2,772,987</td>
<td>$5,669,955</td>
<td>$3,896,120</td>
<td>$28,160,593</td>
</tr>
<tr>
<td>Solid waste existing</td>
<td>$29,956,764</td>
<td>$33,843,188</td>
<td>$41,243,412</td>
<td>$40,731,606</td>
<td>$25,636,836</td>
<td>$26,840,670</td>
<td>$43,813,120</td>
<td>$34,529,047</td>
<td>$276,394,643</td>
</tr>
<tr>
<td>Solid waste new/reactivated</td>
<td>$0</td>
<td>$0</td>
<td>$523,739</td>
<td>$413,503</td>
<td>$261,690</td>
<td>$469,608</td>
<td>$2,411,690</td>
<td>$1,190,758</td>
<td>$5,270,987</td>
</tr>
<tr>
<td>Solar existing</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$66,978</td>
<td>$1,246,337</td>
<td>$2,521,159</td>
<td>$2,371,155</td>
<td>$6,205,629</td>
</tr>
<tr>
<td>Solar new/reactivated</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$66,978</td>
<td>$1,246,337</td>
<td>$2,521,159</td>
<td>$2,371,155</td>
<td>$6,205,629</td>
</tr>
<tr>
<td>Wind existing</td>
<td>$430,065</td>
<td>$1,180,153</td>
<td>$2,011,156</td>
<td>$1,819,413</td>
<td>$1,072,929</td>
<td>$812,644</td>
<td>$1,372,110</td>
<td>$1,491,563</td>
<td>$10,190,033</td>
</tr>
<tr>
<td>Wind new/reactivated</td>
<td>$0</td>
<td>$2,917,048</td>
<td>$6,836,827</td>
<td>$15,232,177</td>
<td>$9,919,881</td>
<td>$5,052,036</td>
<td>$12,898,748</td>
<td>$30,987,962</td>
<td>$83,844,678</td>
</tr>
<tr>
<td>Total</td>
<td>$4,252,287,381</td>
<td>$6,087,147,586</td>
<td>$7,503,218,157</td>
<td>$8,449,652,496</td>
<td>$5,355,087,023</td>
<td>$3,871,714,635</td>
<td>$6,756,928,604</td>
<td>$7,258,389,284</td>
<td>$49,514,425,166</td>
</tr>
</tbody>
</table>

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Figure 4-1 History of capacity prices: Calendar year 1999 through 2014 (See the 2011 SOM, Figure 4-1)
Table 6-2 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year)

<table>
<thead>
<tr>
<th></th>
<th>Energy</th>
<th>Capacity</th>
<th>Synchronized</th>
<th>Regulation</th>
<th>Reactive</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$8,990</td>
<td>$47,188</td>
<td>$0</td>
<td>$0</td>
<td>$2,384</td>
<td>$58,563</td>
</tr>
<tr>
<td>2010</td>
<td>$32,781</td>
<td>$55,186</td>
<td>$0</td>
<td>$0</td>
<td>$2,384</td>
<td>$90,351</td>
</tr>
<tr>
<td>2011</td>
<td>$34,939</td>
<td>$45,972</td>
<td>$0</td>
<td>$0</td>
<td>$2,384</td>
<td>$83,295</td>
</tr>
</tbody>
</table>
Table 6-5 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year)

<table>
<thead>
<tr>
<th></th>
<th>Energy</th>
<th>Capacity</th>
<th>Synchronized</th>
<th>Regulation</th>
<th>Reactive</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$44,553</td>
<td>$50,184</td>
<td>$0</td>
<td>$0</td>
<td>$3,198</td>
<td>$97,936</td>
</tr>
<tr>
<td>2010</td>
<td>$89,027</td>
<td>$58,324</td>
<td>$0</td>
<td>$0</td>
<td>$3,198</td>
<td>$150,549</td>
</tr>
<tr>
<td>2011</td>
<td>$103,726</td>
<td>$48,306</td>
<td>$0</td>
<td>$0</td>
<td>$3,198</td>
<td>$155,230</td>
</tr>
</tbody>
</table>
Table 6-8 PJM-wide net revenue for a CP under Day Ahead dispatch by market (Dollars per installed MW-year)

<table>
<thead>
<tr>
<th></th>
<th>Energy</th>
<th>Capacity</th>
<th>Synchronized</th>
<th>Regulation</th>
<th>Reactive</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$47,467</td>
<td>$47,469</td>
<td>$0</td>
<td>$2,051</td>
<td>$1,783</td>
<td>$98,770</td>
</tr>
<tr>
<td>2010</td>
<td>$119,478</td>
<td>$54,670</td>
<td>$0</td>
<td>$898</td>
<td>$1,783</td>
<td>$176,830</td>
</tr>
<tr>
<td>2011</td>
<td>$70,665</td>
<td>$44,282</td>
<td>$0</td>
<td>$1,025</td>
<td>$1,783</td>
<td>$117,754</td>
</tr>
</tbody>
</table>
Figure 6-4: New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)
### Table 4-8 RPM load management statistics: June 1, 2007 to June 1, 2014 (See the 2011 SOM, Table 4-12)

<table>
<thead>
<tr>
<th>Date</th>
<th>DR and EE Cleared Plus ILR ICAP (MW)</th>
<th>UCAP (MW)</th>
<th>DR Net Replacements ICAP (MW)</th>
<th>UCAP (MW)</th>
<th>EE Net Replacements ICAP (MW)</th>
<th>UCAP (MW)</th>
<th>Total RPM LM ICAP (MW)</th>
<th>UCAP (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-Jun-07</td>
<td>1,708.1</td>
<td>1,763.9</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>1,708.1</td>
<td>1,763.9</td>
</tr>
<tr>
<td>1-Jun-08</td>
<td>4,029.4</td>
<td>4,167.5</td>
<td>(38.7)</td>
<td>(40.0)</td>
<td>0.0</td>
<td>0.0</td>
<td>3,990.7</td>
<td>4,127.5</td>
</tr>
<tr>
<td>1-Jun-09</td>
<td>7,138.3</td>
<td>7,374.4</td>
<td>(459.5)</td>
<td>(474.7)</td>
<td>0.0</td>
<td>0.0</td>
<td>6,678.8</td>
<td>6,899.7</td>
</tr>
<tr>
<td>1-Jun-10</td>
<td>8,892.2</td>
<td>9,199.3</td>
<td>(499.1)</td>
<td>(516.3)</td>
<td>0.0</td>
<td>0.0</td>
<td>8,393.1</td>
<td>8,683.0</td>
</tr>
<tr>
<td>1-Jun-11</td>
<td>10,570.7</td>
<td>10,935.6</td>
<td>(1,205.8)</td>
<td>(1,247.5)</td>
<td>0.2</td>
<td>0.2</td>
<td>9,365.1</td>
<td>9,688.3</td>
</tr>
<tr>
<td>1-Jun-12</td>
<td>9,073.2</td>
<td>9,407.0</td>
<td>(860.8)</td>
<td>(892.6)</td>
<td>(21.4)</td>
<td>(22.2)</td>
<td>8,191.0</td>
<td>8,492.2</td>
</tr>
<tr>
<td>1-Jun-13</td>
<td>10,213.5</td>
<td>10,551.0</td>
<td>(22.4)</td>
<td>(22.2)</td>
<td>0.0</td>
<td>0.0</td>
<td>10,213.5</td>
<td>10,551.0</td>
</tr>
<tr>
<td>1-Jun-14</td>
<td>14,460.7</td>
<td>14,940.5</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>14,460.7</td>
<td>14,940.5</td>
</tr>
</tbody>
</table>
## Table 4-19 OMC Outages: Calendar year 2012 (See the 2011 SOM, Table 4-30)

<table>
<thead>
<tr>
<th>OMC Cause Code</th>
<th>% of OMC Forced Outages</th>
<th>% of all Forced Outages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lack of fuel</td>
<td>79.7%</td>
<td>8.4%</td>
</tr>
<tr>
<td>Other switchyard equipment external</td>
<td>6.1%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Switchyard circuit breakers external</td>
<td>5.4%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Transmission line</td>
<td>4.4%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Transmission equipment beyond the 1st substation</td>
<td>2.3%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Tornados</td>
<td>0.6%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Flood</td>
<td>0.5%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Transmission system problems other than catastrophes</td>
<td>0.4%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Transmission equipment at the 1st substation</td>
<td>0.2%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Switchyard transformers and associated cooling systems external</td>
<td>0.2%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Lightning</td>
<td>0.1%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Switchyard system protection devices external</td>
<td>0.1%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Lack of water (hydro)</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Storms (ice, snow, etc)</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100.0%</strong></td>
<td><strong>10.6%</strong></td>
</tr>
</tbody>
</table>
Table 4-20 PJM EFORd vs. XEFORd: Calendar year 2012 (See the 2011 SOM, Table 4-31)

<table>
<thead>
<tr>
<th></th>
<th>EFORd</th>
<th>XEFORd</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle</td>
<td>1.9%</td>
<td>1.8%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>9.4%</td>
<td>6.3%</td>
<td>3.1%</td>
</tr>
<tr>
<td>Diesel</td>
<td>2.6%</td>
<td>1.4%</td>
<td>1.2%</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>1.0%</td>
<td>1.0%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0.9%</td>
<td>0.9%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Steam</td>
<td>9.3%</td>
<td>8.2%</td>
<td>1.2%</td>
</tr>
<tr>
<td>Total</td>
<td>6.6%</td>
<td>5.5%</td>
<td>1.1%</td>
</tr>
</tbody>
</table>
Table 4-24 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2012 (See the 2011 SOM, Table 4-35)

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>EFORd</th>
<th>XEFORd</th>
<th>EFORp</th>
<th>EFORd and XEFORd</th>
<th>EFORd and EFORp</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle</td>
<td>1.9%</td>
<td>1.8%</td>
<td>0.8%</td>
<td>0.1%</td>
<td>1.1%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>9.4%</td>
<td>6.3%</td>
<td>0.9%</td>
<td>3.1%</td>
<td>8.5%</td>
</tr>
<tr>
<td>Diesel</td>
<td>2.6%</td>
<td>1.4%</td>
<td>0.5%</td>
<td>1.2%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>1.0%</td>
<td>1.0%</td>
<td>1.4%</td>
<td>0.1%</td>
<td>(0.4%)</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0.9%</td>
<td>0.9%</td>
<td>0.8%</td>
<td>0.0%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Steam</td>
<td>9.3%</td>
<td>8.2%</td>
<td>3.3%</td>
<td>1.2%</td>
<td>6.1%</td>
</tr>
<tr>
<td>Total</td>
<td>6.6%</td>
<td>5.5%</td>
<td>2.1%</td>
<td>1.1%</td>
<td>4.5%</td>
</tr>
<tr>
<td>Date</td>
<td>Name</td>
<td>Link</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>------------------</td>
<td>-----------------------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>March 21, 2011</td>
<td>IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875</td>
<td><a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf</a></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>January 20, 2012</td>
<td>IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214</td>
<td><a href="http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf</a></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>February 17, 2012</td>
<td>IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos. ER11-2871-000, -001 and -002, EL11-20-000 and -001</td>
<td><a href="http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_E1-00_20130217.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_E1-00_20130217.pdf</a></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Market Mitigation, Capacity Markets and Market Design: Are They Working As Intended?
Centralized Market for Tomatoes
Tomatoes are Tomatoes are Tomatoes
Bilateral Market for Tomatoes
Another Bilateral Market for Tomatoes

What Is A CSA?

The CSA concept really began well over twenty years ago. Wisconsin has grown to become the number one per capita CSA state in the country. CSA has become a viable option for our farm and the many members who participate with us each year.

CSA stands for Community supported Agriculture. CSA embodies the concept of connecting the farm, crops, and farmer directly to the consumer. You are sharing in the rewards of a farmer's labor as well as a part of the risks associated with farming. When joining a CSA you are purchasing a share or portion of the crops that the farm and farmer produce. You will receive your share weekly throughout the growing season delivered to your choice of pick up sites. Our growing season is anywhere from 20 to 23 weeks long depending on weather conditions. You will receive a wide variety of crops throughout the course of a growing season. As the seasons change so do the crops you receive.

In spring greens are at their best. Lettuce, spinach, green onions, strawberries, and peas are a few of the early crops you may receive. As the warm days of summer arrive, so do crops like tomatoes, cucumbers, summer squash, and sweet corn. As fall arrives, so do potatoes, cabbage, winter squash, and watermelons.

Our CSA hopes to offer you more than just quality fruits and vegetables. We want you to get a feeling of where your produce comes from, who is growing it, and what Wisconsin agriculture is all about. We put out newsletters and updates on what is happening on our farm. We offer recipes for some of those items you may not quite know what to do with. We offer several event days where you can come to the farm and meet with us, see the fields of crops, and harvest some things to take home with you.

The benefits of CSA to local agriculture and the local economy are profound. The average produce item in a grocery store travels over 1300 miles and through a list of warehouses and shipping yards. That is a boat load of money being sent out of country or at least out of state for each vegetable that we consume. Our farm could not survive without CSA and the support of all of our members and their commitment to supporting us and our shared local economy.
People Tend to Give Away Extra Produce
Once you’ve planted the tomatoes, there’s no marginal cost to recover per tomato

You can only store so much

Should Publix or the commercial tomato growers be able to force you to sell your tomatoes at their cost?
Also, People May Actually Pay More to Self Supply
Because A Tomato is NOT just a Tomato
Can you legitimately conclude that the taste, texture, and color of your tomatoes, the lack of chemical fertilizers, the lack of pesticides, and the local production of your tomatoes justifies paying more for them?
If so,

Is the higher price you pay at the Farmers’ Market or for growing your own a subsidy?
So, in the absence of proof of deliberate market manipulation,

- If you pay more than the Publix price:
  - Should you have to get Publix’s approval before you eat the tomatoes you buy at the farmers’ market?
  - Should you have to get Publix’s approval before you eat the tomatoes you grew yourself?
  - Should you have to buy your tomatoes from Publix and throw your own tomatoes away?
Natural Effect of Bilateral Sales and Self Supply on Supermarket Prices

$3.00/lb
$2.00/lb
$1.00/lb
$0.69/lb
The Response of Antitrust Regulators

Tough

The purpose of market regulation is to protect competition, not competitors
Some competitors have figured this out
Electric Markets Should Be No Different

- There isn’t just one centralized market for power. The bilateral wholesale markets, retail markets, and markets for generation assets are legitimate markets.
- Consumers, represented by their load-serving entity or state regulators, should be able to choose from whom to buy their power supply.
- Market signals through both price and product quality.
- Investing in new resources through bilateral transactions or by building one’s own resources are legitimate responses to market signals.
Electric Markets Should Be No Different (2)

- Consumers (and their representatives) should be able to value factors other than predicted future market prices, including:
  - The hedge values of:
    - Ownership or long-term contracts
    - Fuel diversity
    - Proximity
    - Plant vintage
    - Environmental attributes
  - Political, regulatory and consumer good will
  - Economic development
Electric Markets Should Be No Different (3)

- It is not a subsidy to act as a price taker in the capacity market if the total VALUE of the resource to YOU justifies the investment or long-term contract.
  - It’s only a subsidy if you pay more than the total VALUE to YOU of a resource, not if you merely pay more than the RTO’s 20 year estimate of net-levelized future RTO market revenues.
- If consistent with bullet 1, a contract for differences is not a subsidy. It is merely a means for sharing the potential risk and potential reward from an investment.
- “Out of the market” and “out of market” are two VERY different things.
A board of directors that makes a $ Billion investment decision based solely on the RTO’s or IMM’s estimate of 20 year net levelized revenues in the centralized markets is violating its fiduciary duty
“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)
Electric Markets Should Be No Different (5)

- Increased capacity SHOULD reduce capacity market prices. The market shouldn’t provide a signal to invest when capacity is adequate.
- Market regulation shouldn’t guarantee revenues to investors who choose to rely solely on the centralized market for revenues rather than hedging by entering into bilateral or retail transactions.
- If access to bilateral and retail markets provides a competitive edge, that should guide investors’ business decisions rather than forcing changes to the markets.
“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.”

In the absence of proof of intent to manipulate markets, the RTOs, IMMs, and FERC should not be permitted to second guess the reasonableness of consumer choices in the market.
Electric Markets Should Be No Different (7)

- That means:
  - RTO capacity markets should not be mandatory; or,
  - If RTO capacity markets are mandatory, self supply should be guaranteed to clear unless the RTO can demonstrate the intention of a party to manipulate the market.
  - The RPM should be “residual” as FERC and the parties initially intended:
    - 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”.

  *PJM Interconnection, L.L.C. 115 FERC P61,079 at P 55 (2006)*
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.”

Amended MOPR
A Commissioner’s Perspective on the PJM Capacity Markets

Energy Bar Association
Northeast Chapter Annual Meeting
June 6, 2012

Commissioner Wayne E. Gardner
Pennsylvania Public Utility Commission
About the PUC

• Five full-time members
• Nominated by the Governor; approved by a majority in the state Senate
• Staggered 5-year terms
• Governor appoints Chairman; Vice Chairman elected by peers
Industries Regulated by PUC

• Electric
  – PA is a deregulated state

• Natural Gas
  – including gas and hazardous liquids pipeline equipment and facilities

• Water/Wastewater

• Telecommunications

• Transportation
The Pennsylvania Regulatory Model

- Restructured in 1996 with Electricity Generation Customer Choice and Competition Act
- Major characteristics included:
  - Unbundling of generation, distribution and transmission
  - Generation divestiture
  - Retail choice for PA customers
  - Recovery of stranded costs
  - Creation of electric generation suppliers (EGSs)
- Retail electric deregulation in PA coincides with deregulation of wholesale markets
Contrast with Vertically Integrated System

• **EDCs:**
  – Have an historical “obligation to serve”
  – Controlled their own generation assets

• Retail customers’ capacity and energy requirements were always fully met regardless of demand

• Traditional cost of service ratemaking and rate design:
  – Ensured levelized cost recovery, but not true allocation of costs to the actual cost causers
  – Resulted in cross-subsidization between classes

• Transmission and distribution system was designed so any consumer could use as much electricity as the physical characteristics will allow
Prior Statutory Responsibilities Still Apply to PA EDCs

• EDCs:
  – Are “public utilities” under Section 102; Public Utility Code
  – Are obligated to provide adequate, efficient, safe and reasonable service under Section 1501 of the Public Utility Code
  – Have an “obligation to serve” under Section 1501
  – Must continue to meet their obligation to serve within the constraints of a competitive wholesale market
In a Deregulated PA Environment

• EDCs
  – still act as default suppliers
  – are required to procure supply through a competitive “full requirement process” that consists of auctions, RFPs and bilateral agreements (Section 2807 (e) of the Public Utility Code)
  – must enter into a prudent mix of spot market, short-term and long-term contracts

• This process, at the retail level, only works if there is a fully functioning competitive wholesale market
PJM Capacity Markets (2000-12)

• PUC has been active in the development of capacity markets.

• 1999-2000
  — Prior to the genesis of the reliability pricing model, generation capacity in PJM was governed by the installed capacity market (ICAP)
  — ICAP worked adequately until 2004
PJM Capacity Markets (2000-12) cont’d

• 2004
  – PJM identified significant projected shortfall in resource adequacy. PJM says ICAP market not working.

• 2005-06
  – Two years of stakeholder debate on a solution; no consensus reached

• August 2005
  – PJM filed forward capacity solution with FERC; First RPM filing
PJM Capacity Markets (2000-12) cont’d

• April 2006
  – FERC found PJM’s installed capacity adequacy construct to be “not just and reasonable”
  – FERC found PJM’s RPM proposal to be “just and reasonable”; Ordered a settlement process to finalize solution

• December 2006
  – FERC approved settlement implementing the RPM mechanism
The RPM Mechanism

• PJM’s RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources
  – Designed to maintain system reliability in the context of a long run competitive equilibrium in energy markets
  – The PJM Capacity Market is designed to provide revenue adequacy and resultant reliability
PUC Concerns with RPM

- PUC was an active participant in FERC RPM proceeding; neither supported or opposed the RPM settlement at FERC
- In filed comments, PUC expressed concerns that RPM:
  - may not result in fully competitive markets
  - mitigates but does not resolve all market power concerns
- RPM appears to have performed reasonably well in the absence of better options
The Critical Elements of Market Oversight

Independent Market Monitor (IMM)

• Functionally separate from the RTO
• Established in FERC Order 2000
• The market monitoring function was originally part of PJM
• Established as a separate function in 2007
Role of Independent Market Monitor (IMM)

• Keep the RTO, market participants, regulators and the public apprised of the performance of the wholesale electric market
• Monitor the conduct of the RTO in implementing the market rules
• Recommend improvements in market design based upon detailed knowledge about the markets and their operation
• Review the method for calculating cost-based offers used by PJM to apply mitigation measures in the energy markets
FERC Office of Enforcement

• FERC created an Office of Oversight in the 1990’s following a period of limited enforcement authority
• Energy market issues of 2000-01 demonstrated deficiencies in market oversight
• EPA Act of 2005 enhanced FERC enforcement authority
• Order 670 delineated FERC’s enhanced authority with regard to market manipulation and penalties
• Subsequent policy statements have further articulated FERC’s enforcement authority
FERC Office of Enforcement (cont’d)

• Encourages compliance with the Commission’s statutes, rule and orders
• Gathers information about market behavior and market participants
• Implements rules to bring market participants into compliance with FERC provisions
• Conducts audits and investigations to evaluate compliance
• Encourages entities to adopt robust and effective compliance programs and practices
FERC Office of Enforcement (cont’d)

• Focuses on Four Priorities
  – Fraud and market manipulation
  – Anticompetitive conduct
  – Serious violations of the electric reliability standards
  – Conduct that threatens the transparency of regulated markets

• Recent Enforcement Action: Constellation Energy agrees to pay a record $245 million penalty
In Conclusion, the PUC...

- Continues to ensure the “obligation to serve” requirement is fulfilled by EDCs
- Successfully transitioned to a competitive retail market even as generation supply is now market-based
- Must rely on the proper functioning of the wholesale markets in order to perform its role in implementing a competitive retail market.
- Supports the IMM and an active FERC enforcement role
NYISO Capacity Market: How It’s Working

Rana Mukerji
Senior Vice President – Market Structures
Energy Bar Association
Northeast Chapter Annual Meeting
Philadelphia, PA
June 6, 2012

NYISO Capacity Market

- Installed Capacity (ICAP) Requirements are set prior to the start of each capability year
- Load Serving Entities (LSEs) can meet their ICAP requirements by:
  - Self-Supply
  - Bilateral Transactions with Suppliers
  - Forward Auctions (6-month strip and monthly)
  - Deficiency/Spot Market Auctions

Locational ICAP

- Due to transmission constraints into certain zones, some LSEs must procure at least some of their ICAP requirements from resources electrically located within that locality
- New York has locational requirements for two transmission-constrained zones
  - New York City - New York City capacity market is subject to both buyer side and supply side market mitigation measures
  - Long Island
Locational ICAP (New Development)

- September 8, 2011 FERC Order directed the NYISO to develop and file tariff revisions implementing a process to create new capacity zones
- New capacity zone to be created if a “Deliverability Test” indicates the need for it
- Market Mitigation measures to be considered for potential new zones
- Potential new capacity zone process to be coordinated closely with the NYISO’s three-year demand curve reset process

Demand Curve

- Demand Curve used as proxy for LSE Bids
- Improves traditional ICAP market
- Increases system reliability by valuing additional ICAP above the requirements
- Reduces price volatility & sends more stable revenue signal for new resources
- Continues to ensure a competitive, fair, and non-discriminatory market for capacity

Market Outcomes

Since 2000, New York has added:
- Over 9,000 MW of new generation
- Over 1,600 MW of new transmission
- Over 2,000 MW of demand response
### Average Seasonal Spot Market Clearing Prices

**2007/08 to 2010/11 (S/kWh-Mo UCAP)**

<table>
<thead>
<tr>
<th>Season</th>
<th>NYCA</th>
<th>NYC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>$2.36</td>
<td>$2.00</td>
</tr>
<tr>
<td>Summer</td>
<td>$1.35</td>
<td>$1.00</td>
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<tr>
<td>Winter</td>
<td>$1.45</td>
<td>$1.20</td>
</tr>
<tr>
<td>Summer</td>
<td>$1.72</td>
<td>$1.40</td>
</tr>
</tbody>
</table>

### Capacity Surplus in NY

- **High level of excess capacity currently in New York**
  - Estimated to fall in the next few years
    - NPCC: 30% → 25%
    - New York: 32% → 28%
- **Capacity Outlook**
  - Capacity currently exceeds requirements by more than 4,000 MW
  - Average annual growth rate estimated at 0.73% (till 2020)
  - Conservation and demand response participation expected further reduce capacity need
  - Assuming no major retirements, and estimated load, it may take 15 years or more for a system-wide capacity need
  - New environmental regulations may drive retirements and create need for new capacity sooner

### Evaluation of Forward Market Constructs

- **In 2009, the NYISO engaged the Brattle Group to evaluate the costs and benefits of moving to a forward capacity market design**
  - Near consensus among stakeholders that existing ICAP market is working
  - No projected need for new capacity over the next ten years
  - Risks and transition costs of a major redesign not warranted at present
- **In the NYISO shared governance process, stakeholders recommended that the NYISO suspend consideration of a forward capacity market**
- **In 2012, the NYISO will re-evaluate the merits of forward capacity market constructs for the New York market**
References

- New York Independent System Operator, Inc. 137 FERC ¶ 61,218 (2011); 135 FERC ¶ 61,170 (2011); 135 FERC ¶ 61,002 (2011); 134 FERC ¶ 61,056 (2011) (Orders accepting the NYISO’s most recent triennial ICAP demand curve reset).

References

- FERC Docket No. ER12-360 (Tariff revisions to govern the implementation of new capacity zones).
Generator Retirements: Is the Northeast Prepared?
Contents

• New York-Specific Questions to be Answered
• Evolution of the Transmission System
• Reliability Criteria
• Dynegy Experiences in New York
• New York-Specific Provisions
• Conclusions
New York-Specific Questions to be Answered

• If a unit is deemed needed for reliability how will compensation be handled?
• Can a unit operating at a financial loss be required to operate for 6 months...and beyond?
• Does the state PSC have jurisdiction over compensation/rates?
• How are non-transmission alternatives evaluated?
• What roles do the TO and ISO play?
• Transmission system has been historically constructed and built-out around utility-owned generating plants
• When older plants file for retirement, the transmission system is in a position for which not originally designed
  – As older, smaller 115kV-connected plants have retired, the 115 kV networks have been forced to “hang” off the higher voltage systems
  – Circa 1950-1970: 115 kV System was the “Backbone”
  – Circa 1970+: 345kV System has become the “Backbone”
• Higher voltage systems generally more able to absorb retirements
  – But not a given – long transmission lines with high power transfers and little or no dynamic support from generators present operational issues
Transmission Security
– Evaluation of thermal, voltage and dynamic stability performance
– Typically specific to a local area

Resource Adequacy
– Evaluation of the probabilistic loss-of-load expectation, mostly from a supply vs. load standpoint
– Typically evaluated on a pool-wide basis

Each will be evaluated on a retirement-by-retirement basis
– How does the evaluation take into account the totality of the retirements, either announced or potential?
Dynegy evaluated several options for the Danskammer and Roseton facilities, which are financially stressed

- Danskammer connected at 115 kV
- Roseton connected at 345 kV

Dynegy filed for Chapter 11 reorganization of Dynegy Holdings, LLC on November 8, 2011

On November 28, 2011, Interconnecting Transmission Owner filed affidavit by Public Service Commission staff member citing need for facilities’ continued operation

1. U.S. Bankruptcy Court, Southern District of N.Y. Case No. 11-38111
2. Id., Docket #103
• PSC affidavit stated the following:
  – During high load levels, without Danskammer, Central Hudson unable to supply load should a transformer fail
    ▪ Central Hudson working to install a parallel transformer within 11 months
  – Plants also provide “house power” to TOs’ substations, as part of the interconnection Agreement
    ▪ “Building the required facilities potentially could cost several million dollars and take at least one year to complete” ¹
    ▪ “[Interconnecting T.O.] has no contingency plans” ²
    ▪ “It is unknown how many customers will be affected, but the number is likely to be substantial” ³

1. Id., Docket 103, para. 11, p. 5
2. Id.
3. Id., para. 10, p. 5
New York-Specific Provisions

• New York Public Service Commission Generator Retirement Provision\(^1\)
  – >= 80 MW....6 months notice
  – <80 MW....3 months notice
• PSC regulation silent on issue of compensation during the notice provision
• Failure to report will be handled on a case-by-case basis

1. NYS PSC Case 05-E-0889
Conclusions

• Transmission System may not be well equipped to handle retirements
• Cumulative effects of retirements, planned and expected, difficult to quantify
  – How are winners and losers chosen?
• No party wants to approve the retirement out of blame for a reliability gap
• Issue of compensation not well defined
• Processes need to balance competitive interests and need for open and transparent evaluations
Coal at the Crossroads

- Series of EPA regulations issued or in process that adversely impact coal-fired electric generation
- Chief among them for APPA members: “Mercury and Air Toxics Standards” (“MATS”) rule issued in December 2011 (77 Fed. Reg. 9304 (February 17, 2012))
- But the MATS Rule is not the only problem: must also deal with cooling water regulations under Section 316(b) of the Clean Water Act, effluent guidelines, coal ash handling, particulate matter, and limits on carbon dioxide emissions from power plants; cumulative impact is daunting
Timeline for MATS rule compliance is tight under CAA Section 112: three years plus one more year if states permit.

EPA can bring enforcement action under Section 113 of the CAA for injunctive relief, civil penalties, and “other appropriate relief.”

EPA has raised the possibility of an additional year under an “Administrative Order” (AO) in a Memo from its Office of Enforcement dated December 16, 2012 (but would not provide protection from third-party suits).
AO Requirements

- Limited to units that must run for reliability purposes that (A) would otherwise be deactivated or (B) due to factors beyond the control of the owner/operator, have a delay in the installation of controls or need to operate because another unit has a delay.
- Must submit a “timely request” (timing is tricky!)
- Must submit concurrence or analysis by the relevant “Planning Authority” as to why unit is required for reliability, or show why such an analysis cannot be supplied.
- EPA intends to consult as necessary with FERC and/or “other entities with relevant reliability expertise”
APPA Position on Time to Comply

- APPA believes that the timeline for compliance with the MATS rule is not reasonable, especially as applied to public power utilities.
- APPA submitted evidence to EPA during the MATS rulemaking that its affected members estimated they need as long as 77 months to comply, given strictures that apply to them as governmental units (RFP requirements, possible bond referenda to obtain financing needed for retrofits or replacement generation).
APPA filed its own petition for review of the MATS Rule in the DC Circuit on April 13, 2012 (No. 12-1173); this is the first time APPA has sued the EPA in court.

APPA on same day sought reconsideration of the MATS Rule from EPA.

Issues are essentially the same in both filings:

- Whether EPA’s failure to meet the requirements of the Small Business Regulatory Enforcement Fairness Act and Regulatory Flexibility Act, 5 U.S.C. §601 et seq., during the MATS rulemaking renders the Utility NESHAPs arbitrary and capricious, an abuse of discretion, or otherwise contrary to law.

- Whether EPA’s failure to meet the requirements of the Unfunded Mandates Reform Act of 1995, 2 U.S.C.A. §§1331-1335 (2011) (“UMRA”) during the MATS rulemaking, and in particular to consider the effects of the Utility NESHAPs on local government as required by UMRA, renders the MATS arbitrary and capricious, an abuse of discretion, or otherwise contrary to law.
FERC issued Staff Whitepaper in Docket No. AD12-1-000 on 1/30/12 suggesting procedures for advising EPA on requests to EPA for extension of time to comply with MATS rule per the EPA’s AO process

APPA/EEI/LPPC/NRECA filed joint comments on the whitepaper on 2/29/12
Key Recommendations from the Joint Comments

1. Establish an efficient and effective reliability review process whereby EPA and state environmental permitting authorities will give significant deference to decisions of Planning Authorities/RTOs, regional reliability entities, NERC and state commissions/local authorities on the need for more time to complete Utility MACT compliance measures and the potential reliability and system adequacy impacts of such compliance measures.

2. Establish clear benchmarks for evaluating and addressing potential adverse reliability impacts that could result from the Utility MACT rule, whereby EPA, Planning Authorities, RTOs, regional reliability entities, NERC, state commissions and local authorities should apply a broad definition of reliability that includes Resource Adequacy, rather than a narrow, short-term operationally based approach.
More Key Recommendations

3. Facilitate a general framework process whereby Planning Authorities/RTOs, regional reliability entities, NERC, and state commissions are best able to perform their responsibilities and coordinate their activities.

4. Help EPA and permitting authorities to better understand the utility planning and operational context, including the potential for delays in completion of new natural gas pipelines and electric transmission facilities and the role of integrated resource planning.

5. Work with EPA and state permitting agencies to publish on a timely basis a public record of which units receive compliance extension of time and which requests for more time were rejected.
FERC Policy Statement on Advice to EPA

- FERC issued “Policy Statement on the Commission’s Role Regarding the Environmental Protection Agency’s Mercury and Air Toxics Standards” in Docket No. PL12-1-000 on 5/17/12 (139 FERC ¶61,131)
- Copies of requests to EPA for an AO are to be filed with FERC; will be treated as an “informational filing”
- Applicants should submit information similar to that FERC reviews when reviewing a possible violation of NERC standards (P 15), but a statement by FERC that a violation might occur would “not constitute a final determination under Section 215” (n. 21)
Policy Statement Continued....

- FERC comments to EPA will be “largely limited to whether the issue in question may result in a violation of a Reliability Standard” (P 19)
- FERC will review the Planning Authority’s analysis to ensure it is reasonable and adequately supported, thus supporting a finding of a reliability violation; may identify other issues within its jurisdiction
- No right to intervene; comments may or may not be considered if filed, but FERC will not respond to them
Is this a Viable Process?

- APPA’s conclusion is that the procedural path offered for the 5th year is likely more ephemeral than real, given the hoops that must be jumped through at both EPA and FERC.
- It was this conclusion in part that led to APPA’s decision to file its petition for review of the MATS Rule.
- Members most directly affected are in the Midwest, but the regional electric system is a village—if someone gets the flu, we all are at risk.
- Managing this transition is going to be a highwire act.
Capacity Market Redesign

Energy Bar Association, Northeast Chapter
Annual Meeting

Mark Karl
Senior Director, Resource Adequacy
New England Wholesale Electricity Markets

Total market costs over the past five years range from $9 billion to $15 billion

Main Components of Region’s Wholesale Markets

Energy Market

System for purchasing and selling electricity using supply and demand to set the price

Forward Capacity Market (FCM)

Resources compete in a Forward Capacity Auction (FCA); resources selected through this auction receive compensation for having invested in capacity and delivering it in the year-long capacity commitment period(s)
Shift in Energy Production

With addition of new natural gas units, natural gas is dominant fuel in region

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>2000</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>31%</td>
<td>28%</td>
</tr>
<tr>
<td>Oil</td>
<td>18%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>15%</td>
<td>52%</td>
</tr>
<tr>
<td>Hydro and other renewables</td>
<td>13%</td>
<td>13%</td>
</tr>
<tr>
<td>Pumped storage</td>
<td>2%</td>
<td>0.7%</td>
</tr>
</tbody>
</table>

*Other renewables* includes landfill gas, biomass, other biomass gas, wind, solar, municipal solid waste, and misc. fuels.
Low Energy Prices Place Premium on Capacity Market

- Natural-gas-fired power plants are 50% of supply mix
- Low gas prices affect unit dispatch and associated energy revenues
  - Though they help provide regional reliability, some older, less efficient and more expensive units operate only a limited number of hours each year
  - Capacity revenues even more important for units that don’t operate frequently
Other Factors Affecting Capacity Market

- **Excess capacity**
- Investment in energy efficiency and demand response
- Retirement of older units
- Load growth/reductions
- Removal of FCM floor
- FCM redesign

<table>
<thead>
<tr>
<th>Auction Commitment Period</th>
<th>Excess Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>FCA 1 2010/2011</td>
<td>1,772</td>
</tr>
<tr>
<td>FCA 2 2011/2012</td>
<td>4,755</td>
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<tr>
<td>FCA 3 2012/2013</td>
<td>5,031</td>
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<tr>
<td>FCA 4 2013/2014</td>
<td>5,374</td>
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<tr>
<td>FCA 5 2014/2015</td>
<td>3,718</td>
</tr>
<tr>
<td>FCA 6 2015/2016</td>
<td>2,853</td>
</tr>
</tbody>
</table>
Other Factors Affecting Capacity Market

- Excess capacity
- Investment in energy efficiency and demand response
- Retirement of older units
- Load growth/reductions
- Removal of FCM floor
- FCM redesign

Significant EE investment over past few years; more coming
Preliminary estimate:
$3 billion from 2014 to 2020
Other Factors Affecting Capacity Market

- Excess capacity
- Investment in energy efficiency and demand response
- **Retirement of older units**
- Load growth/reductions
- Removal of FCM floor
- FCM redesign
Other Factors Affecting Capacity Market

- Excess capacity
- Investment in energy efficiency and demand response
- Retirement of older units
- Load growth/reductions
- Removal of FCM floor
- FCM redesign
Other Factors Affecting Capacity Market

- Excess capacity
- Investment in energy efficiency and demand response
- Retirement of older units
- Load growth/reductions
- **Removal of FCM floor**
- FCM redesign
Other Factors Affecting Capacity Market

- Excess capacity
- Investment in energy efficiency and demand response
- Retirement of older units
- Load growth/reductions
- Removal of FCM floor
- **FCM redesign**

**SPI**  
**STRATEGIC PLANNING INITIATIVE**

FCM redesign can help region resolve issues identified through the Strategic Planning Initiative.
What’s Up Next?

• FCA 7

  – Earlier this year, the states and over 90% of NEPOOL supported a motion to continue the rules in place for the sixth auction through the seventh auction with:
    • Modified capacity clearing price floor of $3.15/kW-month
    • Enhanced capacity zone modeling (such that Connecticut, NEMA/Boston, Maine, and Rest of Pool will be modeled)
  – February 2013 auction for commitment year 2016-2017
Looking Beyond FCA 7

• FCA 8
  – Implement changes to conform to FERC order
    • Minimum Offer Price Rule
    • Removal of price floor
    • Implementation of more zones

• FCA 9 and beyond
  – Enhancements to capacity market
The Strategic Planning Initiative
A proposed roadmap for the region

• Region and industrywide participation

• Five challenges identified
  1. Resource performance and flexibility
  2. Increased reliance on natural-gas-fired capacity
  3. Retirement of generators
  4. Integration of variable resources
  5. Alignment of planning and markets

• Studies and whitepapers underway
  – Studies: Generation Retirements; Strategic Transmission Analysis; Natural Gas
  – Whitepapers: Aligning Planning and Markets; Roadmap; Natural Gas; FCM Redesign
Categories of Capacity Market Enhancements

ISO recommendations should help region meet the five Strategic Planning Initiative challenges

1. Core capacity product definition and performance incentives
   – Improve definition of the core capacity product
   – Create appropriate performance requirements
   – Add incentives for performance
   – Add consequences for failing to perform

2. System operational needs
   – Identify system operational needs
   – Translate into additional product specifications with appropriate delivery incentives and consequences

3. Locational resource requirements
   – Add specificity to locational requirements
   – Configure market to induce locational responses

Enhancement 1: FCA 9
Seeks to resolve challenges:
- Performance & flexibility
- Natural gas
- Plant retirements

Enhancement 2: FCA 9/10
Seeks to resolve challenges:
- Performance & flexibility
- Natural gas
- Integrating variable resources

Enhancement 3: FCA 9/10
Seeks to resolve challenges:
- Plant retirements
- Alignment markets/planning
Capacity Market Enhancements Only Part of Solution

• Additional solutions needed because enhancements to FCM will take time
  – Earliest enhancements to capacity market would be for FCA 8 (2017-2018)

• ISO actively working on developing proper market mechanisms in to allow resources to make certain types of investment
  – Dual-fuel capability
  – Firm gas supply
  – Transportation

• Other solutions being considered to meet regional challenges
  – Potential energy market and operational design changes
    • Hourly day-ahead and intraday reoffers
    • Aligning natural gas and electricity markets
DEP’s mission is to protect New Jersey’s air, land, water, and natural and historic resources.

Improving air quality for the state of New Jersey is a key priority the Christie Administration.

As we focus on leading New Jersey down the path to a cleaner energy future… we are mindful of the environment and to protecting public health.

The Christie Administration has taken legal and administrative actions to reduce air pollution.

The Governor has targeted out-of-state, coal-fired power plants that are significant polluters of New Jersey air.

This includes lawsuits against coal-fired power plants in western Pennsylvania plants.

Earlier this year, Governor Christie announced that all New Jersey Power Plants will be required to reduce emissions on “Peaker Units” used during High Energy Demand Days by May 2015.

Maintaining the 2015 compliance deadline would eliminate 5 to 20 tons per day of nitrogen oxides that would be emitted by these peaker units.

On January 28, 2011, the Governor signed the Long-term Capacity Agreement Pilot Program (LCAPP) into law.

The legislation is designed to promote the construction of qualified electric generation facilities for the benefit of New Jersey's electric consumers.

The need for new in-state generation is what drove LCAPP.

The projects are natural gas driven, and therefore, cleaner.
Considerations re Generator Retirements and Organized Capacity Markets

Morgan E. Parke
All information, facts and opinions presented herein represent the views of Morgan Parke, and may not or do not represent or reflect any information about, the views or opinions of, any of the affiliates of FirstEnergy Corp. or any of the executives, officers or directors of FirstEnergy Corp. and any of the affiliates of FirstEnergy Corp.
Reliability Considerations for Organized Capacity Markets

Units subject to ‘reliability must run’ arrangements

- 2 blocks of time in play during term of RMR arrangement:
  - delivery years for which a capacity auction has been held, was the unit taken in the auction?
  - delivery years for which capacity auctions have not yet been held, should the unit be offered into the auction?

- Capacity market issues that may arise if nominal term of the RMR arrangement is extended.
Considerations re Capacity Market Efficacy

- Consideration 1 – retired units are delisted prior to an auction
  - PJM OATT, Attachment DD, Section 6.6(g) provides, among other things, that a supplier can avoid the “must offer” requirement by delisting the affected unit.
  - PJM OATT, Section 113 describes the process for “delisting” a unit.
  - PJM OATT, Attachment M, Section IV, describes the “market power” analysis that will be performed by the Market Monitor.
Considerations re Capacity Market Efficacy

- Consideration 2 – remaining units need capital infusion to cover MATS compliance costs
  - PJM OATT, Attachment DD, Section 5.6.1 authorizes suppliers to offer units at increments of 0.1 MW.
  - PJM OATT, Attachment DD, Section 6.4 describes the “Market Seller Offer Caps” that apply to supplier offers.
  - PJM OATT, Attachment DD, Sections 6.7 and 6.8 describe the elements that are used to craft the “Avoided Cost Rate” and the “Projected PJM Market Revenues” that are used to establish the Market Seller Offer Caps.
Consideration 3 – potential for offer a new “Planned Generation Capacity Resource.”

- PJM Manual 18, Sections 4.2.3 and 4.2.4 describes the requirements that must be satisfied for a new unit to be offered as Planned Generation into an RPM auction.
- PJM OATT, Attachment DD, Section 5.14(h) describes the “Minimum Offer Price Rule” – which is a “floor” below which Planned Generation cannot offer.
- PJM OATT, Attachment DD, Section 5.14(c) describes the “New Entry Price Adjustment” – which permits a new unit that sets the clearing price in Year 1 to offer the unit at that clearing price in Years 2 & 3.
Considerations re Capacity Market Efficacy

- Consideration 4 – dealing with the aftermath.
  - State Regulators;
  - Federal Regulators (FERC, DOJ); and
  - Shareholders.
Questions
BIOGRAPHIES
JOSEPH BOWRING

Dr. Bowring is the President of Monitoring Analytics. Since 1999, Dr. Bowring has been the Independent Market Monitor for PJM, responsible for all market monitoring activities of PJM Interconnection. He has extensive experience in applied energy and regulatory economics. Dr. Bowring is frequently called upon to testify before state and federal regulators. He has a PhD in Economics from the University of Massachusetts. Dr. Bowring has taught economics as a member of the faculty at Bucknell University and Villanova University. He has served as senior staff economist for the New Jersey Board of Public Utilities and as Chief Economist for the New Jersey Department of the Public Advocate's Division of Rate Counsel. Dr. Bowring has also worked as an independent consulting economist.
Garry A. Brown  
Chairman, New York State Public Service Commission

Garry A. Brown was confirmed as a Commissioner of the New York State Public Service Commission on December 13, 2007 and was named Chairman on January 2, 2008. His term runs through February 1, 2015.

Mr. Brown has more than 30 years of experience in the public, private and not-for-profit energy and electricity sectors, including previously holding a position as Senior Policy Analyst for the former New York State Energy Office, which had been charged with developing a sustainable and sound energy policy and promoting energy efficiency, while protecting the environment and fostering economic development.

Previously, Mr. Brown had been Vice President, External Affairs and Vice President, Strategic Planning, for the New York Independent System Operator (NYISO), the non-profit entity responsible for the operation of New York’s high-voltage transmission system and bulk power markets. Prior to working with the NYISO, Mr. Brown had been Manager, Government and Market Relations for Sithe Energies, Inc., a nationally known electric power producer.

As PSC chairman, Mr. Brown sits on the State Energy Planning Board. He is also chairman of the New York State Board on Electric Generation Siting and the Environment. He sits on the board of the New York State Energy Research and Development Authority and the board of the Regional Greenhouse Gas Initiative Inc. He is a member of the New York State Broadband Development and Deployment Council.

He is a member of the Advisory Council to the Board of Directors of the Electric Power Research Institute (EPRI). The Edison Foundation Board of Directors created the Institute for Energy Efficiency (IEE), an advisory committee, in which Mr. Brown is also a member. He formerly chaired the Electricity Committee at NARUC.

Mr. Brown received his B.A. from State University College at Plattsburgh and his Masters of Public Administration from the Rockefeller School of Public Affairs at the State University of New York at Albany.

Mr. Brown was born and raised in Williamsville, outside of Buffalo. He and his wife, Linda, reside in Averill Park, and are the proud parents of a son and daughter.
Dorothy Capra bio

In 2011, Dorothy Capra joined the New England States Committee on Electricity (NESCOE) as Director of Regulatory Services. Prior to joining NESCOE, Dorothy spent 11 years as International Power’s Director of Regulatory Affairs for NEPOOL and more recently for PJM. In that capacity, she coordinated regulated activities in New England and PJM and related activities at the Federal Energy Regulatory Commission. While at International Power, Dorothy was elected to terms as Vice Chair of NEPOOL’s Transmission Committee and Vice Chair of its Reliability Committee. Before International Power, Dorothy was with New England Electric System (National Grid) for ten years working in a variety of areas, including transmission and rates. She began her career at a BP Oil refinery in Marcus Hook, PA. Dorothy has an MBA from the Amos Tuck School at Dartmouth and a BS in Chemical Engineering from Washington University in St. Louis.
Anna V. Cochrane became Deputy Director of the Office of Energy Market Regulation (OEMR) in May of 2009. OEMR deals with matters involving energy markets, tariffs and rates relating to electric, natural gas, and oil pipeline facilities and services. OEMR serves the public interest by ensuring just and reasonable rates, tariffs and conditions in natural gas pipeline, oil pipeline and electric power markets.

Ms. Cochrane began her career at the Commission in the area of natural gas pipeline certificates and rates. After 12 years, Ms. Cochrane left the Commission and spent 10 years in the private sector working on natural gas pipeline and electric utility matters. Ms. Cochrane returned to the Commission in 2002 and has held a number of managerial positions of increasing responsibility, including Deputy Director of the Office of Enforcement.
DEAN ELLIS:

Dean Ellis is currently Director, Asset Management with Dynegy Inc. In this capacity, Dean is primarily responsible for optimizing financial performance and managing regulatory affairs of Dynegy’s 3,200 MW of natural gas, coal and oil-fired combined cycle and thermal generation assets in the Northeast. Dean is transitioning to the role of Senior Director, Federal Affairs with Dynegy, in which Dean will be leading the development and execution of Dynegy’s advocacy, government and regulatory relations strategies.
Bio:
James T. Gallagher

James T. Gallagher is Senior Manager for Strategic Planning at the New York Independent System Operator, where he is responsible for establishing the long term strategic direction for the NYISO.

Prior to joining the NYISO in January of 2010, he was Senior Vice President for Energy Policy at the New York City Economic Development Corporation (NYCEDC). In this position, he served as energy policy advisor to Mayor Michael Bloomberg, and he led the Energy Policy Department, which was responsible for implementation of many of the extensive energy related recommendations included in the City of New York’s PlaNYC. He also served as Chairman of the New York City Energy Policy Task Force.

Prior to joining NYCEDC, Mr. Gallagher was Director of the Office of Electricity and Environment (OEE) for the New York Public Service Commission. Before joining the Department of Public Service in 1986, he held senior energy policy positions at Northeast Utilities, the Pennsylvania Governor’s Energy Council, and during the late 1970’s, the Tennessee Valley Authority (TVA), where he was Manager of TVA’s Solar Homes for the Valley Project.

He received a BS in Economics from Lehigh University and an MS in Energy Management and Policy from the University of Pennsylvania.
Since joining the PUC Commissioner Gardner has focused on reliability, price competitiveness, security of supply, and customer service for the consumers and utilities of the Commonwealth, as well as other policies as developed by the legislature and specifically Act 129. Commissioner Gardner serves on the board of directors for the Environmental Quality Board, the Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC), and the Electricity Committee of the National Association of Regulatory Utilities Commissioners (NARUC). Commissioner Gardner also is a member of the Pipeline and Hazardous Materials Safety Administration (Natural) Gas Pipeline Safety Standards Committee.

Immediately prior to joining the PUC, Commissioner Gardner partnered in developing wind power projects in Namaqualand, Northern Cape Province, South Africa.

From April 2002 to December 2005, Commissioner Gardner served as vice president and general manager of Franklin Fuel Cells Inc., where he oversaw its formation, development and day-to-day operations.

Previously, Commissioner Gardner served in several operational and managerial capacities over a 20-plus-year career at PECO Energy Company, including investments, strategy, new business development, field service and power plant operations. Upon formally retiring from Exelon Corporation in 2002, Commissioner Gardner joined EnerTech Capital Partners as a venture partner, where he facilitated investment transactions in the energy and telecom technology sectors, and worked as an operational consultant to EnerTech companies on an interim basis.

Commissioner Gardner holds a Bachelor of Science degree in Business Administration from Drexel University in Philadelphia, is chairman emeritus of the Distributed Power Coalition of America (DPCA), and served on the Steering Committee - Distributed Resources Task Force for the Edison Electric Institute. He also has earned certificates from studies at The Wharton School of the University of Pennsylvania, Cornell University, and the American Management Association in Chicago.

Commissioner Gardner was born in Birmingham, Alabama, and attended high school in Philadelphia. Commissioner Gardner resides in Downingtown, Chester County, PA. He is single with no children (except for Corey, Fatima, Sophia, Natalie, Tahira, Thu, Yamil and of course Natalya. He is also Pop-Pop to DeCor, Madison, Savanah and Hannah).
Steven R. Herling is Vice President of Planning at PJM Interconnection. He is responsible for the oversight of the System Planning Division which includes Transmission Planning, Interregional Planning, Interconnection Projects, Interconnection Analysis, and Resource Adequacy Planning. Mr. Herling has been involved extensively in the development of PJM’s regional transmission expansion planning process and resource adequacy planning process. Recently, he has been actively involved in the development of a number of new backbone transmission projects on the PJM system as well as efforts to enhance coordination of planning activities across ISO/RTO boundaries.

Prior to joining PJM, Mr. Herling worked for the General Public Utilities Service Corporation in systems operations and the American Electric Power Service Corporation in bulk transmission planning. Mr. Herling earned a bachelor of science degree in electric power engineering and a master of engineering degree in electric power engineering, both from Rensselaer Polytechnic Institute. He is a licensed professional engineer in the state of Ohio.
William D. Hewitt, is a partner with Pierce Atwood LLP. Bill focuses his practice on complex regulatory, litigation and appellate matters in state and federal courts and administrative tribunals. His work includes advising a broad spectrum of clients involved in the electric and gas sectors on issues such as pipeline approvals, rate decoupling, power purchase, load aggregation, renewable energy policy and project development, as well as a variety of safety and compliance-related matters. In his litigation practice, Bill has successfully represented both private and regulated businesses in complex energy-related commercial and business disputes. An engineer before attending law school, Bill’s background allows him to provide a unique perspective on both the legal and technical issues faced by energy clients. Bill is recognized by Best Lawyers in America and Chambers USA for his expertise on energy matters and is a member of the American Bar Association and the Energy Bar Association, where he serves as its President.
Mr. Karl is Senior Director of Resource Adequacy at ISO New England. He has overall responsibility for the groups at ISO that operate the forward capacity market, and that perform the load forecasting and planning studies to set the New England resource capacity and local sourcing requirements for that market. In addition his group has responsibility for qualifying generation and demand resources for participating in the market, for performing economic and production cost studies, and is developing processes to assess the tradeoffs between transmission and non-transmission alternatives. Prior to that he was Director of Market Development and Integration and Manager of Market Design where he was extensively involved in the development of the Resource Adequacy/Forward Capacity market, the Forward Reserve Market, the Long Term Transmission Rights process, and was responsible for development of the Market Rules and NEPOOL Manuals for the ISO-NE Standard Market Design.

Mr. Karl has over 30 years of diverse experience in the electric utility industry. He earned his Bachelor’s Degree in Mechanical/Aerospace Engineering and his Master’s Degree in Business Administration from the University of Pittsburgh. Prior to joining ISO New England, his industry experience included both technical and managerial responsibilities for Fossil Fueled and Nuclear Generation Engineering and Operations, Risk Assessment, Regulatory Analysis, Finance, Structured Transactions and System Planning, as well as participating in a number of unregulated electric market related ventures. He had extensive involvement in the restructuring and deregulation of the electric industry in Pennsylvania, including the development of retail choice pilot programs, asset valuation, stranded cost filings, and asset divestiture.
Susan N. Kelly

Susan Kelly serves as Senior Vice President of Policy Analysis and General Counsel for the American Public Power Association (APPA). She joined APPA in September 2004. Ms. Kelly assists APPA and its members in energy policy formulation and with policy advocacy before the Federal Energy Regulatory Commission (FERC), federal courts, and other governmental and industry policy forums.

From 1998–2004, Ms. Kelly was a principal with the Washington, D.C. law firm of Miller, Balis & O'Neil, P.C. She represented cooperatively and publicly owned electric utilities and their trade associations, as well as other governmental entities, assisting them with restructuring-related issues before the FERC, federal appellate courts, and state public utility commissions.

From 1995–1998, Ms. Kelly served as the Senior Regulatory Counsel for the National Rural Electric Cooperative Association (NRECA). She represented NRECA before the FERC, state public utility commissions and courts, and served as a liaison from NRECA to many industry groups.

Ms. Kelly was also with Miller, Balis & O'Neil, P.C. from 1982–1995. During that time, she represented publicly owned natural gas distribution systems before the FERC, and advised them on issues related to the restructuring of the natural gas industry, including contract negotiations with gas suppliers and transporters. She was employed from 1980–1982 as an associate with the Washington, D.C. law firm of Crowell and Moring.

Ms. Kelly earned her J.D. degree with high honors from the George Washington University in 1980, and her A.B. degree in Honors Interdisciplinary Studies and Economics, *magna cum laude*, from the University of Missouri in 1977. She is a member of the District of Columbia Bar, numerous federal appellate court bars, and the Bar of the Supreme Court of the United States.

In March 2008 she was appointed to a one-year term on the Department of Energy’s Electricity Advisory Committee, tasked with helping to define a strategy for modernizing the country’s electricity delivery infrastructure, and assisted with the drafting of its final report, “Keeping the Lights On in a New World” (January 2009). From April 2010 to May 2011, Ms. Kelly served as president of the Energy Bar Association. In November 2010, *Public Utilities Fortnightly* named Ms. Kelly one of its “Groundbreaking Lawyers of 2010.”

Ms. Kelly is a frequent speaker on energy-related topics. She has given presentations to many industry groups, including the National Association of Regulatory Utility Commissioners, the Organization of PJM States, Inc., the National Association of State Utility Consumer Advocates, the Energy Bar Association, the American Bar Association, the American Antitrust Institute, the National Council of State Legislatures, the Consumer Federation of America, the DOE-NARUC Electricity Forum, the Electricity Consumers Resource Council, EEI-Energy Daily, EXNET, Platts, Infocast, New Mexico State University’s Center for Public Utilities, the National Rural Electric Cooperative Association, the American Gas Association, and the American Public Gas Association.
Kevin A. Kirby, P.E.
Vice President, Market Operations

Kevin Kirby joined ISO New England (ISO-NE) in 2000 and serves as Vice President of Market Operations. Mr. Kirby is responsible for the operations and settlements of the multi-billion dollar wholesale electricity markets in New England – including the energy, capacity and ancillary services markets. He is also responsible for market training and customer support for market participants, regulators and other industry stakeholders.

Prior to joining ISO-NE, Mr. Kirby was Vice President, Power Supply at Eastern Utilities Associates (EUA). Throughout his tenure at EUA, he held positions responsible for integrated resource planning, demand-side management, generating plant investments, power supply management, and transmission services. While at EUA he also served as President of Duke Louis Dreyfus New England, an affiliate company organized to build generating facilities, trade power in the deregulated electricity market and sell electricity to commercial and industrial customers.

Mr. Kirby has almost forty years of electric industry experience. He began his career as a power plant design engineer, working on both thermal and nuclear facilities. His experience also includes project design for qualifying facilities and independent power producers, and providing electrical design and engineering services for industrial and municipal electric generation and distribution systems.

Mr. Kirby holds a Bachelor of Science degree in Electric Engineering from Northeastern University. He also serves as a director for the North American Energy Standards Board and is a registered Professional Engineer.
Frank Koza bio

Frank J. Koza, is Executive Director of Operations Support at PJM Interconnection, where he is responsible for the technical staff supporting real time operations. He has worked at PJM for 10 years, all in operations. He is Vice Chair of the NERC Geomagnetic Disturbance Task Force and was formerly Chair of the NERC Operating Reliability Subcommittee. He received a BSME degree from the University of Pennsylvania and a MEng degree from Widener University. He is a registered professional engineer in Pennsylvania. Prior to being employed at PJM, he was employed by Exelon for 29 years in a variety of positions in transmission maintenance, construction, system operations, and system planning.
Michael Krancer  
Secretary, Department of Environmental Protection

Michael Krancer was nominated by Governor Tom Corbett to be the Secretary of Environment Protection (DEP) on January 18, 2011. The nomination was confirmed by the Pennsylvania State Senate on April 26, 2011.

Until he was nominated by Governor Tom Corbett to be Pennsylvania's Acting Secretary of the Department of Environmental Protection (DEP), Mike Krancer was a Judge on the Pennsylvania Environmental Hearing Board (EHB). The EHB is the state-wide trial/appellate court for environmental cases which tries appeals from actions of the DEP. He was first nominated to serve as a Judge on the EHB by Pennsylvania Governor Tom Ridge in October 1999. The Senate of Pennsylvania confirmed the nomination and Mr. Krancer took the oath of office in November 1999. In February 2003, Judge Krancer was named by Pennsylvania Governor Edward G. Rendell as Chief Judge and Chairman. Before becoming a Judge, Mr. Krancer was a litigation partner at the Dilworth and Blank Rome law firms in Philadelphia. His practice involved complex commercial, white collar criminal, and environmental litigation. Judge Krancer stepped down from the EHB in April 2007 to devote full time to his candidacy for Justice of the Pennsylvania Supreme Court. Acting Secretary Krancer became an Assistant General Counsel for the Exelon Corporation in June 2008. While with Exelon he provided legal counsel in the areas of environmental, health and safety compliance and litigation. He also worked on energy policy matters and with the company's government relations team. He was asked by Governor Rendell to return to the EHB as a Judge in 2009.

Secretary Krancer serves on the Board of Directors of Inn Dwelling, a non-profit faith-based initiative corporation associated with St. Vincent de Paul Roman Catholic Church located in the Germantown section of Philadelphia, whose mission is capacity-building among disadvantaged families in the Germantown and Northeast sections of Philadelphia. Judge Krancer worked with Inn Dwelling high school students as a volunteer writing skills coach. Judge Krancer also currently serves on the Board of Trustees of Neumann University, a private, Catholic, co-educational University in the Franciscan tradition, located in Aston, Delaware County and is emeritus on the Boards of Albert Einstein Healthcare Network, the Brodsky Institute for Blood Diseases and Cancer, the Jewish Federation of Greater Philadelphia, the Jewish Publication Group, the Jewish Publication Society and Riverbend Environmental Education Center. At Riverbend he served as Vice President. He and his wife, Barbara, served as Chairs of the Harvest Ball for the Albert Einstein Medical Center.

Secretary Krancer is an active member of the Montgomery Bar Association (MBA) and he has been elected to serve on the Board of Directors and the Executive Committee of the MBA commencing in 2005. He is a former Chairman of the Environmental Law Committee and is an active member of the Municipal Law and Government Relations Committees. He also served on the MBA Judiciary Committee and is a mentor in the MBA mentoring program. He is a frequent faculty lecturer for various Continuing Legal Education programs on various topics including the Pennsylvania Judges' and Attorneys' Code of Civility and lobbying law and practice.

Secretary Krancer is an avid student of Hebrew and Christian Biblical Canon and he has pursued undergraduate and graduate level coursework in theology and biblical studies and exegesis at Villanova University. He is also a student of naval history, especially naval aviation from its dawning through its heyday, the World War II Pacific Campaign. He is a member of the United States Naval Institute and the Navy League of the United States. He is also a Civil War Re-enactor. He is proud to be a Private of the 20th Maine Volunteers, Company E (Army of the Potomac, Fifth Corps, First Division, Vincent's Brigade). He has seen "action" at Gettysburg, Stanardsville and Cedar Creek among other engagements.
Executive Profile

Tamara L. Linde (Tammy)
Vice President - Regulatory

Tamara L. Linde was named vice president - regulatory of PSEG in December 2006. She is responsible for the federal and state regulatory matters of the PSEG companies. Additionally, Tamara manages the corporate legal group within the PSEG law department.

Ms. Linde joined the law department of Public Service Electric and Gas Company (PSE&G), as an attorney in 1990 handling a variety of natural gas and electric regulatory and transactional matters. After holding several other legal positions at PSE&G she became general solicitor, in 2000. In that position she was responsible for the regulatory affairs of the PSEG companies including electric, gas and nuclear matters. She has had significant experience working on regulatory matters before various state and federal regulatory agencies on industry issues relating to electric transmission and distribution and energy markets.

Ms. Linde is a member of the New Jersey, New York, District of Columbia and Texas bars and served as chair of the Energy Bar Association Electricity Regulation and Compliance Committee during the 2009-2010 term. Ms. Linde graduated from Seton Hall University School of Law and from Seton Hall University with a bachelor’s degree. She currently serves on PSEG’s Compliance Council, PSEG’s Disclosure Committee and PSE&G’s Real Property Committee. Ms. Linde also serves as a member of the Board of Trustees of New Jersey After 3, a non-profit organization dedicated to expanding after school opportunities for New Jersey’s kids.
Richard Miller is Director of the Energy Markets Policy Group at Con Edison, which advocates on federal energy policy issues and represents the company at the New York ISO and PJM RTO. Previously he was an assistant general counsel in the regulatory services department at Con Edison where he worked on legal matters relating to the Con Edison steam system, renewable power and energy efficiency. From 1998-2003, he was Senior Vice-President for Energy at the New York City Economic Development Corporation (where he oversaw City energy policy). Prior to 1998, he was an energy regulatory attorney for Cohen, Dax & Koenig in Albany, New York, and a litigation associate at Cohen, Weiss and Simon and Sullivan & Cromwell in New York City. He is a graduate of Amherst College and New York University School of Law. From 1980-1982, Mr. Miller was a Peace Corps Volunteer in West Africa.
Commissioner Philip D. Moeller is serving his second term on the Commission, having been nominated by President Obama and sworn in on July 16, 2010, by Congresswoman Cathy McMorris Rodgers (R-Wash.), for a term expiring June 30, 2015. He was first nominated to FERC by President George W. Bush in 2006 and sworn into office on July 24, 2006, by Chief Justice of the United States John Roberts.

From 1997 through 2000, Mr. Moeller served as an energy policy advisor to U.S. Senator Slade Gorton (R-Washington) where he worked on electricity policy, electric system reliability, hydropower, energy efficiency, nuclear waste, energy and water appropriations and other energy legislation.

Prior to joining Senator Gorton's staff, he served as the Staff Coordinator for the Washington State Senate Committee on Energy, Utilities and Telecommunications, where he was responsible for a wide range of policy areas that included energy, telecommunications, conservation, water, and nuclear waste.

Before becoming a Commissioner, Mr. Moeller headed the Washington, D.C., office of Alliant Energy Corporation. Prior to Alliant Energy, Mr. Moeller worked in the Washington office of Calpine Corporation.

Mr. Moeller was born in Chicago, and grew up on a ranch near Spokane, Washington.

He received a B.A. in Political Science from Stanford University.
BIOGRAPHY

JAY MORRISON
VICE PRESIDENT, REGULATORY ISSUES

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.
Rana Mukerji
New York Independent System Operator
Senior Vice President, Market Structures


Before joining the NYISO, Mr. Mukerji spent seven years with ABB in Raleigh and Zurich where he was Vice President and General Manager and Group Senior Vice President. At ABB, Mr. Mukerji had global responsibility for ABB’s Power Technology Asset Management and Consulting services. He also led ABB’s $500 million global Utility Partner Business, overseeing 3,000 employees in 35 countries.

Mr. Mukerji was with General Electric in Schenectady, N.Y. from 1990 to 1999 where he was General Manager of GE’s Power Systems Energy Consulting business. At GE, Mr. Mukerji implemented the Six Sigma quality improvement program in the Power Systems Energy Consulting organization, and helped establish the GE-MAPS software as an industry standard tool for evaluating competitive power markets.

Mr. Mukerji graduated from the Indian Institute of Technology with a Bachelor’s degree in Electrical Engineering. He earned a Master of Engineering degree in Electric Power Engineering and an MBA from Rensselaer Polytechnic Institute, Troy, New York.

He is also a Professional Engineer registered in the state of New York.
Steven T. Naumann

Steven T. Naumann is Vice President – Transmission and NERC Policy at Exelon Corporation. He is responsible for developing policy for Exelon on transmission pricing, cost allocation, and high level transmission planning policy nationwide. He also directs the development of reliability policy issues relating to standards, compliance and other issues involving the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Federal Energy Regulatory Commission (FERC). Mr. Naumann joined Commonwealth Edison Co. following service as an officer in the United States Air Force. During his over 35 years at Exelon and Commonwealth Edison, Mr. Naumann has held a number of engineering, managerial and executive positions responsible for the planning, operation, and security of the electric delivery system. He has participated on a number of committees, working groups and task forces of NERC and the Mid-America Interconnected Network Regional Reliability Council (MAIN), including serving as Vice Chairman of MAIN from 2004-2005. Mr. Naumann has served on NERC Member Representatives Committee as a representative of the Investor Owned Utilities and later served as Vice Chairman and Chairman. He has testified before Congress, FERC, the Illinois Commerce Commission and the Public Service Commission of Wisconsin.

Mr. Naumann received a Bachelor of Science degree in Electric Power Engineering in 1971 and a Master of Engineering degree in Electric Power Engineering in 1972, both from Rensselaer Polytechnic Institute in Troy, New York. He later received a J.D. degree from Chicago-Kent College of Law in 1988. Mr. Naumann is a Registered Professional Engineer in the State of Illinois and is licensed to practice law in Illinois.
Education

Massachusetts Institute of Technology, Ph.D. in Technology Management and Policy; Stanford University, M.S. in Materials Science and Engineering; Harvard University, A.B. in Chemistry and Physics

Biography

Dr. Samuel Newell, Principal of The Brattle Group, is an expert in electricity wholesale markets, the transmission system, and RTO rules. He supports clients throughout the U.S. in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation, transmission development, demand response programs, and integrated resource planning. He has written expert reports for RTOs and provided testimony before state regulatory commissions and the FERC.

For his clients, Dr. Newell has most recently:

Submitted testimony to FERC on the public policy, congestion relief, and reliability benefits of a proposed 6,000 MW offshore DC backbone from New Jersey to Delaware to Maryland to Virginia with multiple interconnection points for offshore wind. Testimony was on behalf of the Atlantic Wind Connection Companies in their FERC filing for incentive rates.

Authored reports for MISO, PJM, ISO-NE, and NYISO evaluating their capacity market designs and demand response programs, and recommending improvements. Solicited extensive input from stakeholders.

Produced a 10-year integrated resource plan with the Connecticut electric utilities evaluating the cost and environmental implications of alternative energy efficiency and procurement strategies. Considered renewables mandates, likely environmental regulations, potential generation retirements, and market uncertainties.

Developed energy and capacity price forecasts for the developers and buyers of generation; analyzed both market-related and asset specific investment risks, based on review of documents in the "data room."

Built capacity market models and performed power market simulations to evaluate smart grid programs/investments, new transmission, generation retirements, RTO seams issues, and vertical market power.

Dr. Newell also has in-depth experience with all major electricity market simulation models and leads The Brattle Group's own locational market modeling of U.S. RTO markets.

Prior to joining The Brattle Group, Dr. Newell was Director of the Transmission Service at Cambridge Energy Research Associates. Before that, he was a Manager in the Utilities Practice at A.T.Kearney.
Morgan Parke is Senior Corporate Counsel for FirstEnergy Service Company, where he advises the FirstEnergy executives and companies on federal regulatory matters. While at FirstEnergy, Morgan has counseled executives on matters related to:

- federal regulation of RTO entry and exit decisions;
- wholesale capacity market auction design and implementation;
- wholesale capacity auction rules and bidding strategies;
- utility merger-related issues as regulated by the FERC and the U.S. Department of Justice;
- transmission project cost allocation policies and positions;
- regulatory compliance programs;
- siting of electric transmission facilities; and
- contested hydroelectric licensing proceedings.

Prior to joining FirstEnergy in 2006, Morgan was in private practice at Couch White, in Albany, New York, where he advised clients on:

- RTO matters that arose under the tariffs of the New York Independent System Operator and the Independent System Operator of New England;
- electric and natural gas retail rates cases;
- energy and environmental matters, including siting matters related to electric generation and transmission facilities, and gas transmission facilities;
- wholesale electric and natural gas procurements and contracts, and
- business and regulatory matters related to certain reversionary rights in certain hydroelectric projects that were developed more than 50 years ago in concert with construction of the New York City’s potable water collection and distribution system.

Turning to the subject of this panel, in recent months, Morgan has advised FirstEnergy’s executives regarding certain decisions related to generator retirements, and the resulting need to address reliability and capacity market issues that may result from such retirements.
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.
Andrew K. Soto is Senior Managing Counsel for Regulatory Affairs at the American Gas Association, representing AGA’s natural gas distribution member companies before the U.S. Department of Energy, the Federal Energy Regulatory Commission, the Commodity Futures Trading Commission, and other Federal agencies and U.S. courts. Mr. Soto advises member companies on regulatory and legislative developments that affect gas utility interests and advocates on their behalf on a broad range of policy issues, involving the regulation of physical and financial natural gas markets and Federal energy conservation standards.

Before joining AGA, Mr. Soto was counsel in the law firm of Sutherland Asbill & Brennan LLP, where he advised clients on regulatory policy developments and compliance in several energy industries including natural gas. Prior to that, Mr. Soto was Senior Legal Advisor to Chairman Pat Wood, III, of the Federal Energy Regulatory Commission. While there, Mr. Soto advised the chairman on the full gamut of issues before the Commission. Prior to joining the Chairman's staff, Mr. Soto represented FERC in complex appellate litigation before U.S. Courts of Appeals in all areas of Commission regulation.

Mr. Soto was previously in private practice at Ball Janik, LLP, and Newman & Holtzinger, PC, and worked in the Office of Administrative Law Judges, U.S. Department of Labor. Mr. Soto received a J.D. from Villanova University School of Law and a B.A. from Franklin & Marshall College.
Thomas L. Welch
Chairman, Maine Public Utilities Commission

Tom Welch was appointed to the Maine Public Utilities Commission as Chair in April 2011. He had previously served as Chair of the Commission from 1993-2005. Between his Commission appointments, Commissioner Welch worked for PJM Interconnection, a Pennsylvania-based Regional Transmission Organization, and for five years was an attorney at Pierce Atwood, LLP, in Portland, Maine, specializing in energy and utility law. Before moving to Maine in 1993, he served as Chief Deputy Attorney General for Antitrust in the Pennsylvania Attorney General's Office, in-house counsel for Bell Atlantic, and Assistant Professor at Villanova University School of Law. Commissioner Welch graduated from Stanford University in 1972 and received his law degree from Harvard Law School in 1975. His term on the Commission expires March 2017.
David Whiteley is the Executive Director of the Eastern Interconnection Planning Collaborative (EIPC). The EIPC is comprised of a group of Planning Authorities from the Eastern Interconnection that are currently advancing the concept of an open and transparent approach to performing transmission system analyses at the interconnection level. Mr. Whiteley provides a leadership role in the EIPC effort and is the owner of a private consulting firm, Whiteley BPS Planning Ventures LLC.

Prior to starting his own consulting company, Dave was employed by the North American Electric Reliability Corporation (NERC) as Executive Vice President from March, 2007 to March 2009. In that position, he was responsible for overseeing NERC’s activities in Standards; Reliability Readiness; Training, Education, and Personnel Certification; Event Analysis; Metrics and Benchmarking; and Members’ Forums.

Prior to NERC, Dave was Senior Vice President - Energy Delivery Services for Ameren Corporation – a position he assumed in January 2005 after serving as senior vice president, Energy Delivery, since October 2003. At Ameren, he was responsible for the planning, design, construction and technical support for all electric transmission and distribution systems for Ameren’s operating utility companies – AmerenCILCO, AmerenCIPS, AmerenIP and AmerenUE. Dave was also responsible for transmission operations and the transmission interface with the Midwest Independent System Operator (MISO) – the regional transmission operator for Ameren. He also led the company’s transmission policy area and served on various task forces and committees of the Edison Electric Institute, the North American Electric Reliability Council, and the Association of Edison Electric Illuminating Companies. Dave started his career as an assistant engineer in the System Planning Department of Union Electric Company in 1978.

A native of St. Louis, Dave earned a bachelors degree in electrical engineering from Rose-Hulman Institute of Technology, Terre Haute, Indiana. He holds a masters degree in Electrical Engineering from the University of Missouri-Rolla completed in 1985. He was granted a Professional Degree in Engineering from the Electrical Engineering Department of the University of Missouri-Rolla in 2004. Dave is a registered professional engineer in the states of Missouri and Illinois. He is also a member of the National Society of Professional Engineers and the Institute of Electrical and Electronics Engineers.